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WHITE RIVER SHALE PROJECT

Prevention of Significant Deterioration of Air Quality • Oil Shale Tracts Ua and Ub • 1981

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WHITE RIVER SHALE PROJECT
1315 WEST HIGHWAY 40
VERNAL, UTAH 84078
(801) 789-0571

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August 28, 1981

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Mr. Steve J. Durham
Regional Administrator
U.S. Environmental Protection Agency
Region VIII
1860 Lincoln Street
Denver, Colorado 80203

Dear Mr. Durham:

The White River Shale Project is applying to the U.S. Environmental Protection Agency and the Utah Bureau of Air Quality for permission to construct and operate a commercial oil shale processing facility on Federal Prototype Oil Shale Tracts Ua and Ub. The proposed facility is located in northeast Utah about 50 miles southeast of Vernal, Utah.

Attached for your consideration and approval are six copies of the Prevention of Significant Deterioration (PSD) preconstruction permit application for the project. This application fully describes a phased development project commencing with a demonstration module operation and progressing in an orderly manner into commercial operation. The proposed project complies with federal guidelines concerning the approval of phased construction projects.

As described in the application, WRSP plans to develop the oil shale resource of Tracts Ua/Ub in three phases. During Phase I, our demonstration program, an underground room-and-pillar mine will be developed to produce up to 27,330 tons per stream day (TPSD) of crushed oil shale. The shale will be processed in two surface retorts and the resulting shale oil upgraded on-site to yield up to 14,840 net barrels per stream day (BPSD) of oil. The knowledge gained during operation of the Phase I facilities will be used to design and construct our commercial facilities. It is planned that Phases II and III will mine 96,460 and 176,740 TPSD of oil shale and produce up to 57,190 and 106,230 net BPSD of upgraded shale oil, respectively.

The PSD application presents in detail the existing regional air quality and meteorology based upon extensive field monitoring, the sources and levels of pollutant emissions from the project, the rationale for selecting pollution control techniques applicable to each source, and a complete evaluation of the air quality impact of the project's construction and operation. The cumulative impact of WRSP and other nearby projects for which PSD applications have been submitted or approved is also presented.

The application shows that the proposed White River Shale Project will comply with all currently applicable state and federal emission and air quality regulations. Your expeditious approval of this permit application will be appreciated. If you have questions concerning this project, please contact me.

Sincerely,

James W. Godlove

James W. Godlove
Environmental Affairs Coordinator

JWG:ddb

Attachments (6)

cc: Peter A. Rutledge - OSO
Henry O. Ash - OSEAP
Lloyd H. Ferguson - BLM
Brent Bradford-UBAQ

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WHITE RIVER SHALE PROJECT

PRECONSTRUCTION AIR PERMIT APPLICATION
PERMIT APPLICATION SIGNATURES

1. Applicant Name: WHITE RIVER SHALE PROJECT

2. Applicant Address: 1315 West Highway 40
Vernal, Utah 84078

3. Applicant Telephone: (801) 789-0571

4. Person To Contact: Mr. James W. Godlove
Environmental Affairs Coordinator

5. Facility Location: On Utah Highway 45 approximately 5 miles south of Bonanza, Utah

6. Type of Operation: Mining and processing of oil shale to produce commercial quantities of shale oil

7. Anticipated Start of Construction:
Phase I December 1, 1981

8. Certification:
"I certify under penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment."

9. Signatures:
For PHILLIPS PETROLEUM COMPANY, as part owner of the WHITE RIVER SHALE PROJECT,

Mr. Kenneth L. Smalley, Vice President
Minerals Group
Phillips Petroleum Co.

For SOHIO SHALE OIL COMPANY, as part owner of the WHITE RIVER SHALE PROJECT,

Dr. Donald B. Anthony, Vice President
Sohio Shale Oil Company

For SUNOCO ENERGY DEVELOPMENT CO., as part owner of the WHITE RIVER SHALE PROJECT,

Mr. Clyde V. Hornback, President
Sunoco Energy Development Co.

WHITE RIVER SHALE PROJECT

Prevention of Significant Deterioration of Air Quality • Oil Shale Tracts Ua and Ub

Submitted by Phillips Petroleum Company • Sohio Shale Oil Company • Sunoco Energy Development Co.
Prepared by Bechtel Petroleum, Inc. • San Francisco • Job 14188 • August 1981

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Section 1

SUMMARY

1.1 PURPOSE AND OBJECTIVES

The White River Shale Project (WRSP) is applying to the United States Environmental Protection Agency and to the Utah Bureau of Air Quality for permission to construct and operate a commercial oil shale processing facility on Federal Prototype Oil Shale Tracts Ua and Ub. The two tracts are located in northeast Utah about 50 miles southeast of Vernal, Utah.

This application is submitted for review under the U.S. Environmental Protection Agency's Prevention of Significant Deterioration regulations (40 CFR Part 52.21) as amended by the August 7, 1980 Federal Register at 45 FR 52676 through 52748. Review is also being requested by the Utah Bureau of Air Quality under the Utah Air Conservation Regulations (26-15-5 and 26-24-5 Utah Code Annotated, 1953) as amended in February 1980.

The application being submitted describes fully a phased development project commencing with a modular operation and progressing in an orderly manner into commercial operation. The project, as herein proposed, complies with the U.S. Environmental Protection Agency's guidelines concerning the approval of phased construction projects. Specifically, construction will begin within 18 months of receiving permit approval, planned construction breaks will not exceed 18 months duration, and the project will submit to periodic reviews of the plans to install the best available pollution control technology prior to commencing construction of subsequent phases of the project.

1.2 GENERAL NATURE OF BUSINESS

The WRSP contemplates joint development of Tracts Ua and Ub. Tract Ua is leased by Phillips Petroleum Company and Sunoco Energy Development Company. Tract Ub is leased by Sohio Shale Oil Company. The WRSP represents and is responsible to each of these three companies in the development of Tracts Ua and Ub.

The WRSP plan for recovering oil from shale consists of mining oil shale using underground room-and-pillar techniques, crushing the shale rock, transporting the crushed shale to surface retorts where product oil and off gas are separated from the shale, upgrading the product oil to be suitable for pipeline transport off site, and disposing of the processed shale in a nearby canyon in a manner that is environmentally acceptable. By-product off gas and some upgraded shale oil will be combusted on site, primarily to provide energy for plant operations.

The White River Shale Project plan is based upon staged development of mining, processing, and related operations in three phases. Phase I is a modular program of relatively small scale. During Phase I up to 27,330 tons per stream day (TPSD) of shale rock will be mined and processed to yield up to 14,840 net barrels per stream day (BPSD) of upgraded shale oil. The knowledge gained during Phase I will permit the refinement of those techniques best suited to process shale from Tracts Ua and Ub on a larger scale. Subsequently, Phases II and III will mine 93,460 and 176,740 TPSD of shale and produce approximately 57,190 and 106,230 net BPSD of upgraded shale oil, respectively.

Figures 1-1 and 1-2 are block flow diagrams showing the various steps required for the production of shale oil in Phase I (modular) and Phases II and III (commercial).

Section 2 of this application presents the project development and scheduling plans. Section 3 locates and describes Tracts Ua and Ub and the proposed

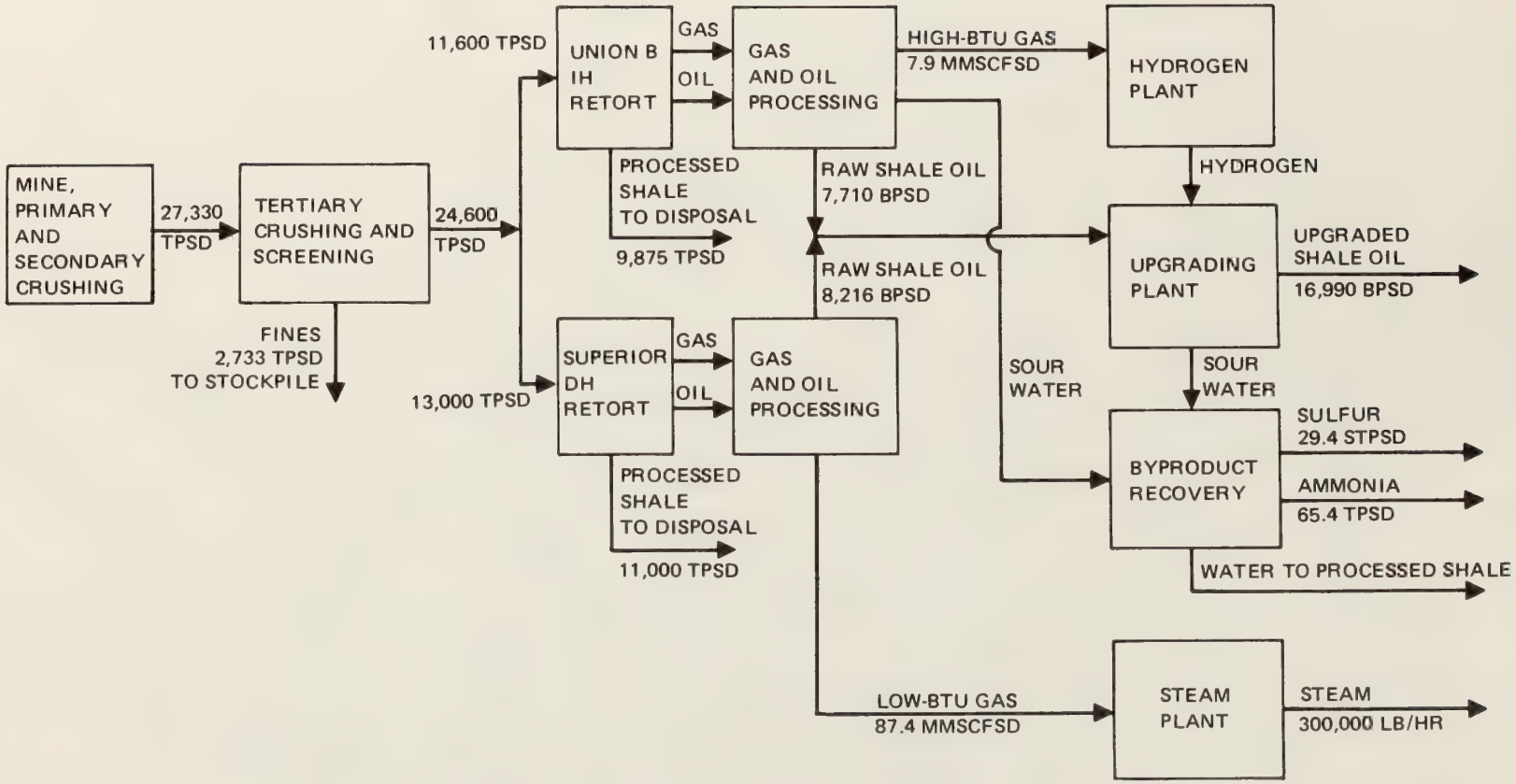


Figure 1-1 PROCESS BLOCK FLOW DIAGRAM – PHASE I

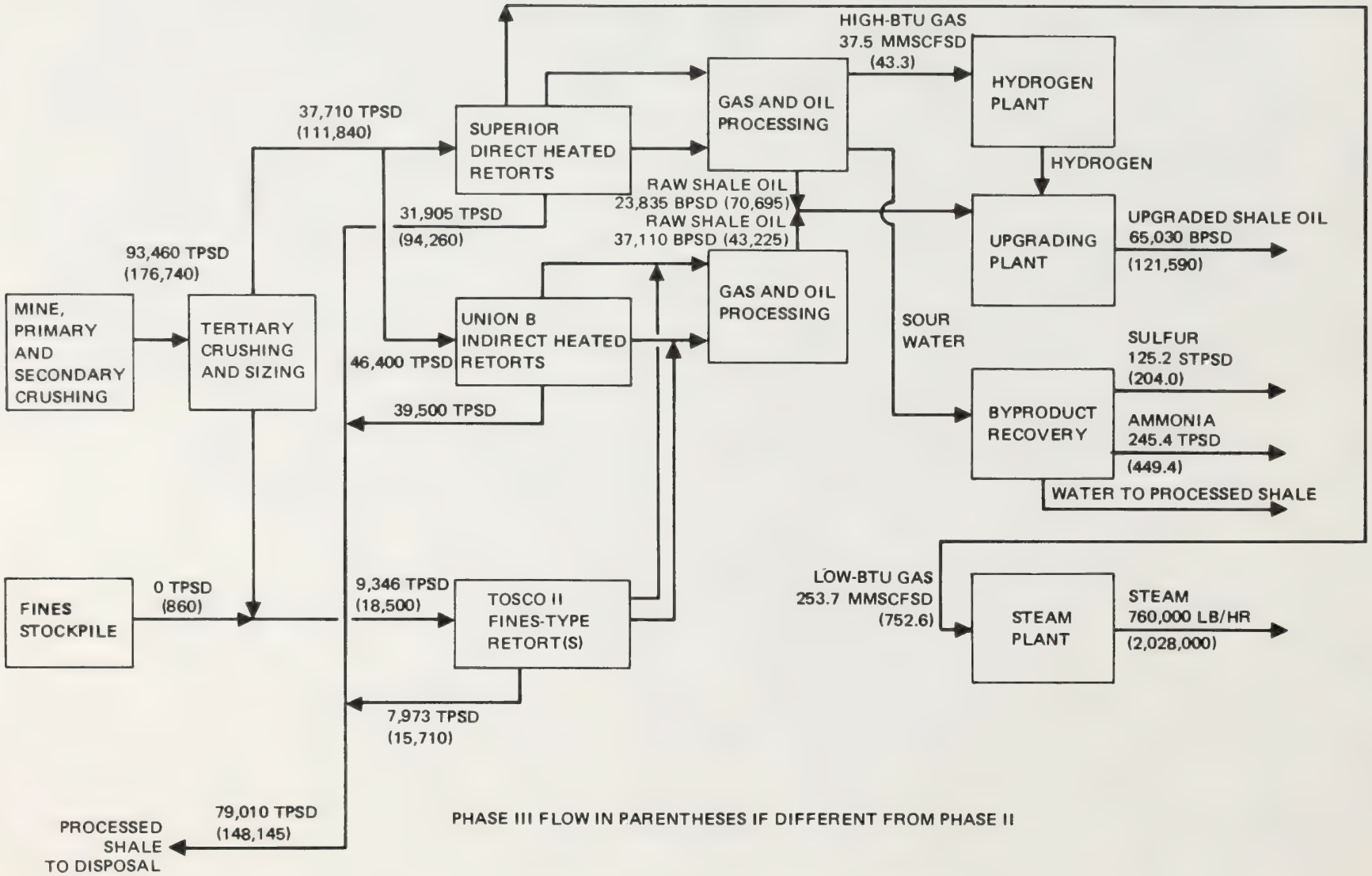


Figure 1-2 PROCESS BLOCK FLOW DIAGRAM – PHASES II AND III

WRSP plant layout. Section 4 describes in detail the various process facilities included in the project. Section 5 provides an estimate of air pollutant emissions from WRSP and their point of emission for dispersion modeling purposes. This section also provides support for our pollution control technology and stack height selections. Section 6 describes the results of ambient air monitoring studies conducted by WRSP for 6 years. Section 7 describes the results of the dispersion modeling studies of the airborne emissions from WRSP. Section 8 describes the associated impacts of WRSP on visibility, soils and vegetation, and related growth.

1.3 SITE EVALUATION

Studies have been conducted characterizing the air, water, geological, biological, historical, and aesthetic resources of the two oil shale lease tracts. During 1975 and 1976 a thorough multidisciplinary environmental baseline program was completed resulting in the publication of a Final Environmental Baseline Report in October 1977 (Ref. 1-1). Subsequent to this baseline period, an interim monitoring program has continued to evaluate long-term trends in the air, water, and biological resources of the tracts with reports published annually (Ref. 1-2).

The tract area can be described as semi-arid, with long, cold winters and short, hot summers. Annual precipitation ranges from 8 to 11 inches, depending upon elevation and terrain. These climatological factors have contributed to the development of desert-like biological populations of both plants and animals.

Air quality near the tracts has consistently been very good, as expected for such a remote location. Surface air flow on the tracts is complicated by the rough terrain. During the early morning, air generally flows along drainage channels from higher to lower elevations. Afternoon air flow is stronger, less variable, and generally from the west or southwest.

Surface water resources in the area include the White River, located along the northern boundary of the tracts, and Evacuation Creek, which is a tributary of the White River and flows part of the year. Groundwater is present on tract, but the yields are quite low.

Section 3 provides greater detail concerning the site.

1.4 EMISSIONS SUMMARY

A detailed discussion of the process facilities is provided in Section 4. Section 5 presents the project air emissions data and BACT (best available control technology) discussion. The maximum expected emission of the air pollutants during each phase of the project is summarized in Table 1-1.

Table 1-1

MAXIMUM EXPECTED EMISSIONS FROM PROJECT OPERATIONS

Air Pollutant	Phase I ton/yr	Phase II ton/yr	Phase III ton/yr
Particulate	285	782	1,515
Sulfur Dioxide	510	853	1,175
Carbon Monoxide	477	1,443	3,407
Hydrocarbons	190	761	1,477
NO_x	1,236	4,097	7,366

Based upon current knowledge of air pollutant emissions from oil shale processing, it is anticipated that emissions of lead and all non-criteria pollutants except sulfuric acid mist will not exceed the current *de minimis* levels established in the PSD regulations. Sulfuric acid mist emission quantities and air quality impacts are minimal (as discussed in Sections 5 and 7, respectively). Since WRSP is a participant in the Federal Oil Shale Prototype Program, one of whose goals is the characterization of project-related environmental effects, steps will be taken during plant operation

to quantify these emissions where their presence is probable and available data do not allow quantification.

1.5 AIR QUALITY IMPACTS

Applicable state and federal airborne emission and ambient air quality regulations were thoroughly reviewed as part of this application.

As a first step in evaluating the air quality impacts of WRSP, baseline air quality values were established. A discussion of the ongoing monitoring program, baseline air quality, and their relation to federal and state requirements is presented in Section 6. The baseline air quality values in Table 1-2 represent the mean annual average of data collected by WRSP from 1978 to 1980.

Table 1-2

BASELINE AIR QUALITY VALUES
(Mean Annual Averages)

Air Pollutant	Background Concentration
Particulate (TSP)	15.7 $\mu g/m^3$
Sulfur Dioxide (SO_2)	1.3 $\mu g/m^3$
Nitrogen Oxides (as NO_2)	1.3 $\mu g/m^3$
Carbon Monoxide (CO)	0.2 mg/m^3

To predict the air quality impact associated with the project, two computerized mathematical models were used. The models are identified as "VALLEY," and "REM2." The results of this study are presented in Section 7.

VALLEY is a part of the EPA's UNAMAP series of atmospheric dispersion models. VALLEY was modified to reflect more closely the plume behavior that exists

in the complex terrain of Tracts Ua and Ub. This program was used to evaluate both ambient air concentrations and increment consumption for each applicable averaging period for the pollutants TSP, SO_2, NO_x, and CO.

REM2 is a reactive model developed for the EPA to predict photochemical contaminant levels. It was used to evaluate future ozone air quality concentrations near Tracts Ua and Ub.

The air quality impacts of operating Phases I, II, and III were predicted. The predicted maximum concentrations of particulates, NO_2, SO_2, CO, and O_3 were compared with applicable national standards and PSD increments for all phases' operations. No violations are expected. Phase III impacts approached Class II increments near tract boundaries for particulates. However, analysis of the WRSP combined with other permitted projects in the area still demonstrated compliance with the standards.

Table 1-3 summarizes the maximum predicted ambient air concentration and increment consumption (where appropriate) for TSP, SO_2, and NO_x; it represents the cumulative impact of the White River Shale Project plus the TOSCO Sand Wash Project and the Moon Lake Project — two other organizations in the area applying for or with permits to operate. For each pollutant discussed in this application, the concentrations shown reflect project impact at off-tract ground level receptors.

The cumulative air quality impact was also analyzed for nearby Class I PSD areas. The nearest Mandatory Class I areas are both 130 kilometers from the WRSP. However, impacts for the PSD criteria pollutants were calculated for Dinosaur National Monument, which has been under consideration for designation as a Class I area and is 55 kilometers north of the

Table 1-3

MAXIMUM PREDICTED OFF-TRACT CONCENTRATIONS[a]

Pollutant	Phase	Maximum Concentration[b] ($\mu g/m^3$)			Distance From Nearest Source (m)	Applicable Standards (μ/m^3)	
		Back-ground[c]	Increment	Total		PSD Class II Increment	NAAQS[d]
Annual:							
TSP	I	15.7	3.8	19.5	860	19	60
	III		16.5	32.2	570		
SO_2	I	1.3	12.0	13.3	860	20	80
	III		14.1	15.4	570		
NO_2	I	1.3	20.5	26.4	860	—	100
	III		79.2	80.5	570		
24-hour							
TSP	I	15.7	7.7	23.4	100	37	150
	III		36.8	52.5	100		
SO_2	I	1.3	22.7	24.0	860	91	365
	III		22.0	23.3	1,200		

(a) Phase II cumulative values are less than Phase III and are not presented here.

(b) Includes maximum concentration contribution from the Moon Lake Project, and the Tosco Sand Wash Project.

(c) Mean annual average values measured in 1978, 1979, and 1980.

(d) The NAAQS values are primary standards for SO_2 and NO_2 and secondary standards for TSP.

WRSP. It is expected that impacts at the other areas will be less than the values projected for Dinosaur because of the greater distance.

The maximum cumulative annual average increments for Phase I were predicted to be 0.056 and 0.029 $\mu g/m^3$ for SO_2 and particulates, respectively. The corresponding values for Phase III are 0.39 and 0.32 $\mu g/m^3$. These impacts are well under the annual average Class I PSD increments of 2 $\mu g/m^3$ and 5 $\mu g/m^3$.

The maximum cumulative 24-hour average increments for Phase I were predicted to be 0.13 and 0.09 $\mu g/m^3$ for SO_2 and particulates, respectively, and 0.81 and 0.60 $\mu g/m^3$ for Phase III. These maximum impacts are all lower than the Class I 24-hour average PSD incremental standards of 5 and 10 $\mu g/m^3$.

1.6 SECONDARY IMPACTS

Additional air quality analyses were made: 1) air quality impact from growth associated with WRSP, 2) impact of the project on visibility, and 3) project impact on vegetation and soils. The results of these studies appear in Section 8.

Associated growth impact analyses began with an estimate of population growth resulting from the WRSP development. Appropriate emission factors were then applied to this population estimate. Only small air quality and visibility impacts were determined to occur in the region.

Project visibility impact was evaluated at the Dinosaur National Monument. The results indicate that the worst conceivable visibility impact at the Dinosaur National Monument from the WRSP is likely to be minimal in terms of both plumes visible against the sky and plumes visible against the terrain; it is expected to be insignificant or imperceptible in its effect on the visual range and sky-terrain contrast.

Fine particles emitted from the plant and subsequently deposited near the facility were studied for possible impact on soil and vegetation. These emissions could potentially affect soils and vegetation in the immediate vicinity of the emitting process. Beyond the tract boundary, however, the concentrations of all criteria pollutants are predicted to be below the National Secondary Ambient Air Quality Standards which were established to protect public welfare. Since conversion products such as SO_4, NO_3, and H_2SO_4 are also expected to be minimal, damage to vegetation and soils is not likely to result from project operation.

REFERENCES

1-1 Final Environmental Baseline Report, White River Shale Project, VTN, Denver, Colorado, October 1977.

1-2 Progress Report, Environmental Program, 1977, WRSP, Vernal, Utah, July 1978,

and

Progress Report, Environmental Program, 1978, WRSP, Vernal, Utah, July 1979,

and

Progress Report, Environmental Program, 1979, WRSP, Vernal, Utah, September 1980.

2. INTRODUCTION

Section 2

INTRODUCTION

2.1 THE OIL SHALE PROTOTYPE PROGRAM

In June 1971, the Secretary of the Interior announced plans for an oil shale development program. At that time, he released a preliminary environmental statement (Ref. 2-1), a program statement (Ref. 2-2), and reports prepared by the states of Colorado, Utah (Ref. 2-3), and Wyoming on environmental costs and problems of oil shale development. These actions followed President Nixon's energy message in which he asked the Secretary of Interior to initiate a "leasing program to develop our vast oil shale resources, provided that environmental questions can be satisfactorily resolved."

The resulting prototype program is designed to develop U.S. oil shale resources by the following plan of action:

- Develop mining and retorting technology for oil shale production
- Stimulate private industry to produce commercial quantities of oil from shale
- Ensure that the environmental integrity of the area is maintained to the greatest degree possible
- Develop methods and technology to protect the environment
- Permit an equitable economic return for all parties
- Develop leasing management expertise for oil shale production

The Department of the Interior requested nominations in November 1971 of proposed tracts for lease, and 20 individual tracts of oil shale land were

nominated. In April 1972, with the concurrence of the states concerned, the Department announced the selection of six of these tracts: two each in Colorado, Utah, and Wyoming.

The program is essentially unchanged from the one announced in June 1971. But the preliminary statement issued at that time was expanded to 1) consider the impact of mature oil shale development, 2) examine the impact of developing the six specific tracts, and 3) include a comprehensive analysis of energy alternatives.

The draft of the Final Environmental Statement was released by the Department of the Interior to the public in September 1972. Subsequent public review, ending in November 1972, provided important information for expanding and correcting the draft material, where appropriate. The Final Environmental Statement for the Prototype Oil Shale Leasing Program was issued in August of 1973 (Ref. 2-4). That document is based on information from many sources, including research data and pilot programs developed by both the government and private industry over the past 30 years. Many factors — such as changing technology, eventual oil production levels, and attendant regional population increases — are not precisely predictable. However, the impact analysis is regarded as a reasonable treatment of the potential regional and specific environmental effects associated with oil shale development.

The Federal Oil Shale Leasing Program is under the supervision and administration of the Department of the Interior, through its Oil Shale Office in Grand Junction, Colorado. That office is directed by the Deputy Conservation Manager — Oil Shale, formerly the Area Oil Shale Supervisor.

To assist and advise the Department of the Interior about environmental matters connected with the operation of oil shale leases, an Oil Shale Environmental Advisory Panel (OSEAP) was established by the Secretary of

the Interior in accordance with the provisions of the Federal Advisory Committee Act, Public Law 92-463 (Ref. 2-5). The OSEAP is composed of members appointed from bureaus within the Department and from other interested federal agencies, members representing state and local governments, and members of the general public active in environmental matters. The function of the panel is to promptly advise the District Manager of the Bureau of Land Management, the Deputy Conservation Manager — Oil Shale, and any other officers or employees of the Department about environmental matters involving their respective responsibilities under the Prototype Oil Shale Leasing Program.

2.2 LEASE ISSUANCE AND STATUS

The six tracts selected in Colorado, Utah, and Wyoming for the Federal Oil Shale Leasing Program all involved the rich Green River Formation; oil yield from this mineable zone may average 30 gallons per ton of shale. Competitive bidding on the six tracts took place from January to June 1974, and bids were received and accepted on both tracts in Utah and in Colorado. No bids were made on the Wyoming lands.

Both of the Utah leases (Ref. 2-6) went into effect June 1, 1974 (Tract Ua: Department of the Interior, Bureau of Land Management Oil Shale Lease Number U-25918; and Tract Ub: Department of the Interior, Bureau of Land Management Oil Shale Lease Number U-26194). Tract Ua was leased by Phillips Petroleum Company and Sun Oil Company (Delaware). Sun Delaware's interest was later fully assigned to Sunoco Energy Development Company. Tract Ub was originally leased by the White River Shale Oil Corporation, comprising Phillips Petroleum Company, Sun Oil Company (Delaware), and Sohio Petroleum Company. This lease was fully assigned to Sohio Petroleum Company and, since then, to Sohio Shale Oil Company. Together, these three companies constitute the White River Shale Project (WRSP).

The terms of both leases were suspended effective November 1, 1976 because of environmental questions that had to be resolved before the leased properties could be developed. The suspension was for a term of one year.

Before the suspension expired, the owners of the leases to Tracts Ua and Ub were granted a preliminary injunction against the Department of the Interior that indefinitely suspended the terms, conditions, and obligations of the leases. The injunction ruling was based on the existence of conflicting claims on the title to Tracts Ua and Ub. This injunction is still in effect, but progress is being made toward resolving the questions.

2.3 THE WHITE RIVER SHALE PROJECT

The White River Shale Project provides for the development of oil shale resources on Federal Lease Tracts Ua and Ub in northeastern Utah. The White River plan discussed in this document calls for staged development of mining, processing, and related operations in three phases, as shown in Figure 2-1.

Phase I comprises mining and retorting designed to generate specific information on ore body characteristics that cannot be determined by core drilling, and information on the retorting process itself. In this phase, up to 27,330 tons per stream day (TPSD) of shale will be mined, yielding 14,840 barrels per stream day (BPSD) of net upgraded shale oil, and stockpiling 2,730 TPSD of fines. Phase I operation will permit selection of those techniques best suited to producing oil from this shale on a larger scale, and in a manner that is environmentally sound and economically viable.

Phase II (93,460 TPSD) and Phase III (176,740 TPSD) will increase the upgraded shale oil production to levels of 57,190 and 106,230 BPSD, respectively, and will continue to the exhaustion of the oil shale resources of the tracts. This plan includes the support facilities needed at each stage of development, including water, power, and access requirements.

2.3.1 Project Organization

The White River Shale Project contemplates joint development of Federal Lease Tracts Ua and Ub, and this PSD permit application has been prepared on that basis. Tract Ua is leased by:

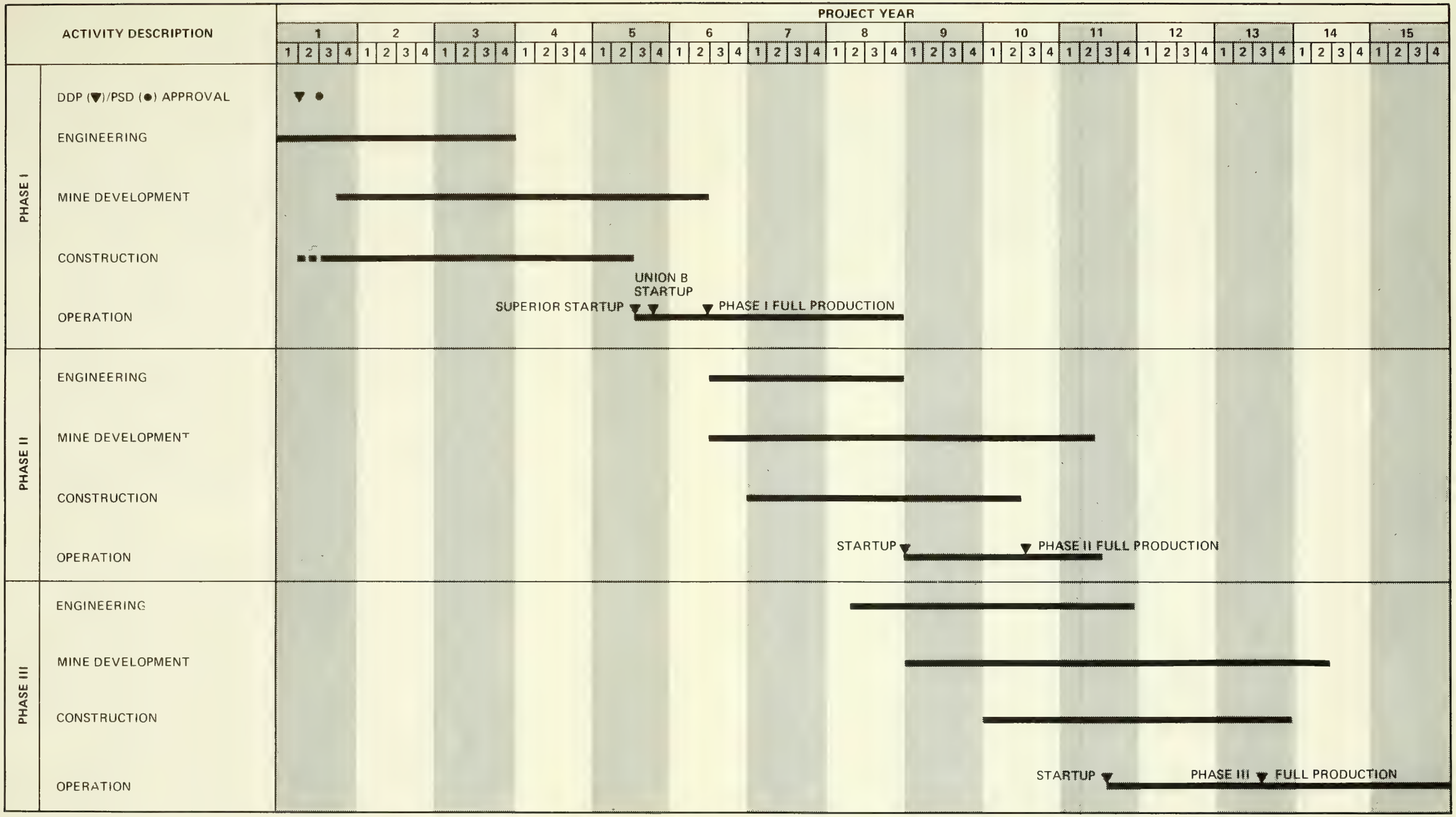


Figure 2-1 WHITE RIVER SHALE PROJECT SCHEDULE

- Phillips Petroleum Company
  700 East Belleview Avenue
  Englewood, Colorado 80111

- Sunoco Energy Development Co.
  12700 Park Central Place
  Dallas, Texas 75251

Tract Ub is leased by:

- Sohio Shale Oil Company
  930 Crossroads Tower
  50 South Main
  Salt Lake City, Utah 84111

2.3.2 Tracts Ua and Ub

Maps and more detailed descriptions of Tracts Ua and Ub are found in Section 3 of this PSD permit application and the supporting documents, Final Environmental Baseline Report, White River Shale Project (Ref. 2-7), project annual reports (Ref. 2-8), and the White River Shale Project Detailed Development Plan (Ref. 2-9).

2.3.3 Project Development

A project schedule for future White River Shale Project (WRSP) activities is presented in Figure 2-1, and a brief description of the project follows. A more detailed description of the items shown on the schedule is found in Section 4.

Preliminary Planning. Early planning was described in a Preliminary Development Plan (Ref. 2-10) submitted in April 1974 in accordance with the Department of the Interior's Prototype Oil Shale Leasing Program and with instructions published by the Department of the Interior in the Federal Register of November 30, 1973 (Ref. 2-11). It is important to note that this was a preliminary plan to be modified as additional data and information became available. At that time, the lessee intended to discuss in a general way

the development of Tracts Ua and Ub, realizing that a great deal of additional information was needed to prepare the present plan (Ref. 2-9).

Exploratory and Baseline Activities. Exploration, coring, and environmental baseline activities were begun on and near the tracts in the summer and fall of 1974. The primary objective of these activities was to develop and install various monitoring stations for baseline data collection. Test wells were drilled and surveyed, and air and water monitoring stations were placed in operation before the winter season (1974-75). The preliminary activity on the tract was governed by the lease and CFR Title 43, Part 23, and Title 30 (Ref. 2-12) concerning surface exploration, mining, and reclamation of public lands.

Environmental monitoring activities were continued after completion of the 2-year environmental baseline monitoring program in January 1977. Additional new data were collected, previous findings investigated, techniques refined, and the baseline data base extended. This interim monitoring program is continuing.

Initial Mine Access and Phase I Retort Operation. The WRSP will start with sinking three mine shafts and developing a room-and-pillar mining operation. This will be followed, in accordance with the schedule, by enlarging the mining operation and installing two surface retorts and upgrading facilities suitable for processing shale and for producing 14,840 BPSD of net upgraded shale oil.

The objectives of Phase I are as follows:

- To initiate a significant level of mining activity on Tracts Ua and Ub in order to establish rock mechanics, gas content, retorting and crushing characteristics, and other operation characteristics of the shale rock

- To prove commercial-sized surface retorting by operating two large-scale units, and to provide a basis for selecting a retort technology for use in Phases II and III

- To ascertain production costs at near-commercial scale in order to define the economics of producing shale oil
- To determine accurately the environmental effects of operating the commercial demonstration facilities, and the means of mitigating and controlling adverse effects
- To begin these operations with an orderly development of facilities, personnel, and actions designed to fit into and become part of the future phases as far as practicable

Commercial Facilities Construction and Processing. Successful operation of the Phase I retort installation will be followed by engineering and construction of two further phases for the commercial production of shale oil. The resulting output capacity of upgraded shale oil will be 57,190 net BPSD after Phase II, and 106,230 net BPSD after Phase III.

The plan for commercial shale oil production and processing comprises mining, crushing, aboveground retorting, and product upgrading. In Phases II and III, mining operations will produce about 93,460 and 176,740 TPSD of raw shale, respectively. The mine will employ proven room-and-pillar techniques, modified as necessary on the basis of the experience gained during Phase I. Mining will recover approximately 63 percent of the oil shale resource within a 55-foot-high mine zone. The raw shale will be prepared as retort feed by several stages of crushing and screening, with primary and secondary crushing carried out in the mine. The coarse-crushed raw shale will be lifted to the surface, where it will be fed directly to Superior retorts or will undergo tertiary crushing and be reduced to an appropriate size for retorting in the Union B retorts. A stockpile of crushed raw shale will be maintained to ensure steady operations.

Most of the raw shale from the crushing operation will be processed in Union B and Superior retorts to achieve the gas quantity and composition required by subsequent process operations and by the process heat balance. The remainder of the crushed raw shale (fines) will be stockpiled in Phase I, and will be processed in fines-type TOSCO II retorts during Phases II and III.

The crushed raw shale will be fed to the retorts by covered conveyors, which will also transport the processed shale to an on-tract disposal site, Southam Canyon. In Southam Canyon, which is in the western section of Tract Ua, the processed shale will be placed in accordance with a program designed to permit handling of these very large quantities of material in a manner that is structurally, environmentally, and economically sound.

Other onsite process facilities will consist of gas treating for sulfur recovery, wastewater treating, sour water stripping, product storage, product movement, relief and blowdown systems, utilities, water supply, wastewater treatment, solid waste handling, and maintenance and administrative facilities. During Phase III, sulfur produced from the facility will amount to approximately 204 TPSD and will be stockpiled for possible future recovery. Up to 450 TPSD of ammonia from product upgrading facilities will be recovered and used at a nearby market, probably in the form of anhydrous ammonia.

In Phase III, the raw shale oil from the facility will have the approximate properties shown in Table 2-1. It will then be upgraded by hydrotreating and the addition of pour point depressants to permit pipeline transport during all three phases.

Table 2-1

PROPERTIES OF SHALE OIL[a]

Property	Raw Shale Oil			Combined Upgraded Shale Oil
	Superior DH Retorts[b]	Union B IH Retorts[c]	Tosco II IH Retorts[b]	
Ultimate Product Quantity, BPSD	70,700	30,840	12,420	106,300
Pour Point, F	85	30	80	75
Gravity, °API	21	20.2	22.0	37.5
Viscosity, CS @ 100F/210F	-/6.3	35.3/4.8	22/3.8	15/2
Sulfur Content, wt %	0.6	0.6	0.7	0.001
Nitrogen Content, wt %	1.4	1.9	1.9	0.10[d]

(a) Data obtained from private communication between WRSP and retort manufacturers, 1980-1981.
(b) Colorado shale.
(c) Utah shale.
(d) Entire C_5+ oil product; fuel oil fraction may reach 0.15 wt % N_2.

Support Facilities. Electric power will be purchased from Moon Lake Electric Association, Inc. during construction and operation of all three phases. Moon Lake operates a power line near Tracts Ua and Ub that is adequate to supply the quantities of power required during early periods. For later periods, the power lines may require upgrading or installation of supplementary lines to carry the plant load requirements. During Phases II and III, there will be some onsite generation of electrical power. However, no power will be exported.

During Phase I, water will be drawn from alluvial wells along the White River. Later, water will come from a supply available from a dam on the White River proposed for construction by the state of Utah. In the commercial phases, a pump station near the water's edge will raise the required quantity of water from the reservoir to the project site as needed.

Upgraded shale oil from Phase I will be transported by pipeline via existing rights-of-way to a refinery in Salt Lake City, Utah. During later phases, an additional pipeline will be required to transport a portion of the upgraded shale oil to other refineries.

REFERENCES — SECTION 2

2-1 Preliminary Environmental Statement, U.S. Department of Interior, Washington, D.C., June 1971.

2-2 Draft Environmental Impact Statement for the Proposed Prototype Oil Shale Leasing Program, Volume III, U.S. Department of the Interior, Washington, D.C., September 1972.

2-3 Prospects for Oil Shale Development: Colorado, Utah, and Wyoming, U.S. Department of the Interior, Washington, D.C., May 1968.

2-4 Final Environmental Statement for the Prototype Oil Shale Leasing Program, U.S. Department of the Interior, Washington, D.C., 1973.

2-5 Federal Advisory Committee Act, Public Law 92-463, as published in the Federal Register, Vol. 39, No. 45, March 6, 1974.

2-6 Federal Oil Shale Leases, Nos. 25918 and 26194.

2-7 Final Environmental Baseline Report, White River Shale Project, VTN, Denver, Colorado, October 1977.

2-8 Progress Report, Environmental Program, 1977, WRSP, Vernal, Utah, July 1978,

and

Progress Report, Environmental Program, 1978, WRSP, Vernal, Utah, July 1979,

and

Progress Report, Environmental Program, 1979, WRSP, Vernal, Utah, September 1980.

2-9 White River Shale Project Detailed Development Plan (in press), WRSP, Vernal, Utah, 1981.

2-10 Prototype Oil Shale Leasing Program, Utah Tract Ua, Preliminary Development Plan, submitted by Phillips Petroleum Company and Sun Oil Company, Delaware, March 1974,

and

Prototype Oil Shale Leasing Program, Utah Tract Ub, Preliminary Development Plan, submitted by the White River Shale Oil Corporation, April 1974.

2-11 Federal Register, Vol. 38, No. 230, Part III, U.S. Department of the Interior, Washington, D.C., November 30, 1973.

2-12 Federal Register, Code of Federal Regulations, Title 43, Part 23, and Title 30, Vol. 23, No. 852, Washington, D.C., January 18, 1969.

3. SITE DESCRIPTION AND FACILITY LAYOUT

Section 3

SITE DESCRIPTION AND FACILITY LAYOUT

3.1 LOCATION AND DESCRIPTION

Tracts Ua and Ub lie immediately south of the White River in the eastern part of the Uinta Basin in a remote part of northeastern Utah. Tract Ua lease is in Uintah County, Utah and contains 5,120 acres, more or less. It includes:

T. 10 S., R. 24 E., SLM, Utah
- Sec. 19, E½
- Sec. 20, All
- Sec. 21, All
- Sec. 22, All
- Sec. 27, All
- Sec. 28, All
- Sec. 29, All
- Sec. 30, E½
- Sec. 33, N½
- Sec. 34, N½

Tract Ub lease is in Uintah County, Utah and contains 5,120 acres, more or less. It includes:

T. 10 S., R. 24 E., SLM, Utah
- Sec. 12, S½, S½N½
- Sec. 13, All
- Sec. 14, All
- Sec. 23, All
- Sec. 24, All
- Sec. 25, W½W½
- Sec. 26, All

T. 10 S., R. 25 E., SLM, Utah
- Sec. 18, All
- Sec. 19, All

A map showing the location of the two tracts is presented in Figure 3-1. The nearest community is Bonanza, about 5 miles north of Tract Ub, with a population of about 20; the nearest town in Utah having a full range of services is Vernal, about 50 miles northwest, with a population of about 6,600 (1980); and the nearest town in western Colorado is Rangely, about 30 miles away, with a population of about 2,100 (1980). Vernal is served by U.S. Route 40 and Bonanza by Utah Route 45. From Bonanza, the tracts and the proposed process areas can be reached by dirt roads that are not a part of the state system.

The only major perennial stream in the area is the White River, whose valley occupies a narrow strip about 800 feet wide at the northern edge of Tracts Ua and Ub. The canyon of Evacuation Creek, usually a perennial stream, trends northward across the central part of Tract Ub. West of Evacuation Creek, the terrain is more rugged and is characterized by ledges and cliffs along the canyon walls and numerous buttes along the drainage divides.

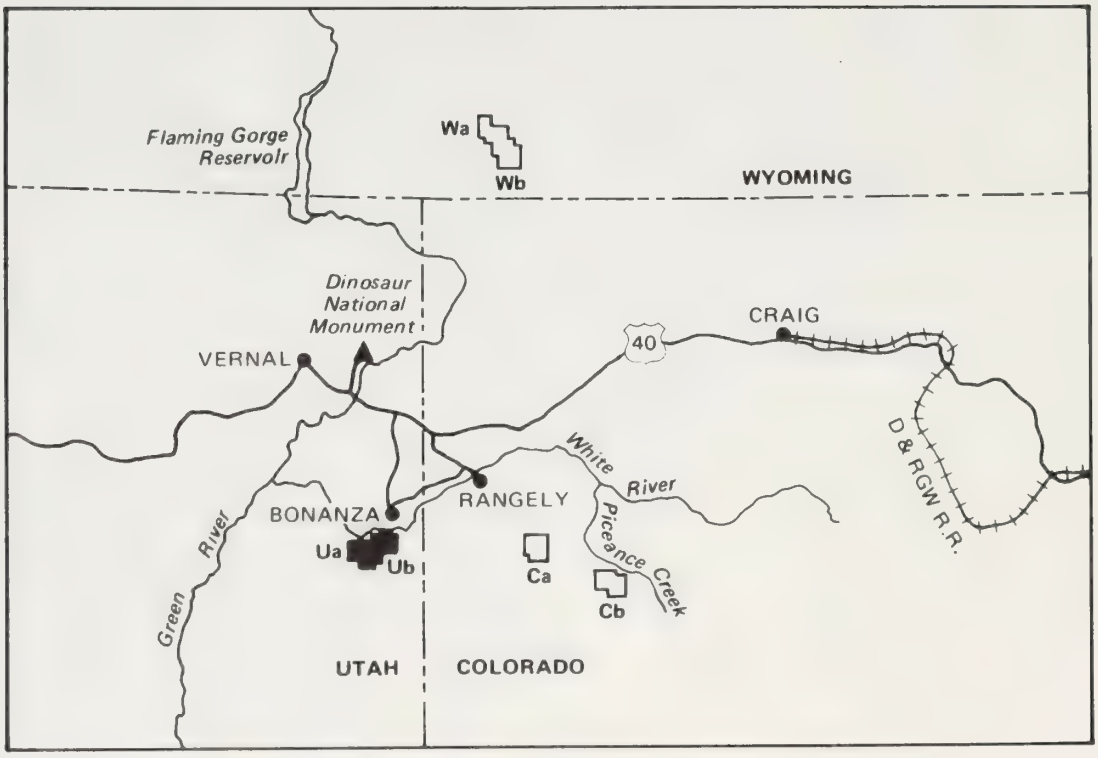


Figure 3-1 LOCATION OF TRACTS Ua AND Ub

Southam Canyon, a slightly meandering ephemeral drainage, extends northwestward across Tract Ua and joins the White River just outside the tract. Ground cover in both tracts is sparse, consisting mostly of shrubs. Surface elevations within the tracts range from 4,900 feet at the White River to approximately 5,960 feet in the south-central part of Tract Ua. The greatest altitude difference in a short distance is about 450 feet in 0.5 mile in the south-central part of Tract Ua.

3.1.1 Climate and Air Resources

The climate of Tracts Ua and Ub is semiarid. Annual precipitation ranges from approximately 8 inches at lower elevations to 11 inches over higher terrain, with about 4 inches from May to September (mostly from thunderstorms) and about 6 inches from October to April. Approximately 30 to 40 days per year have more than 0.01 inch of precipitation. Severe local thunderstorms in summer may cause strong, gusty winds and local flash flooding.

The average annual snow accumulation is about 10 inches, but open areas may remain free of snow for most of the winter.

The area has dry hot summers, with a 5-year average July maximum temperature of 95F, an extreme of 97F, and an average July mean of 75F. The winters are relatively dry and cold. The 5-year average minimum for January is -10F, the extreme minimum recorded is -22F, and the average January mean is 15F. The frost-free period is approximately 144 days.

Surface airflow on the tracts is complicated by rough terrain effects. During the early morning hours, the air generally flows along drainage channels toward low terrain and along the White River. In the afternoon, winds are stronger and less variable, flowing generally from the west or southwest. Air quality on the tracts, with few exceptions, has consistently been very good, as is expected for a remote location.

Section 6 contains climatological and meteorological data obtained at the site during the monitoring program and baseline air quality data.

3.1.2 Geology

The Uinta Basin is a sedimentary, structural, and topographic basin. Oil shale of the Green River Formation is exposed along the south and east margins of the basin, and is concealed by younger sediments in the central and northern parts of the basin. Available drilling information indicates that the thickest, richest oil shale is in the eastern half of the basin, mostly concealed by younger rocks of the Uinta Formation. Geologic maps and a description of the oil shale in the southeastern part of the Uinta Basin are contained in Reference 3-1.

The Green River Formation conformably underlies the Uinta Formation and is composed of the Parachute Creek, Garden Gulch, and Douglas Creek members. The Parachute Creek Member is of major interest because it contains the rich oil shale sequence known as the Mahogany Zone.

The Parachute Creek Member consists of finely laminated siltstones, marlstones, and oil shales with numerous thin tuff beds, deposited in a deep-water lacustrine environment. Oil shale is commonly defined as kerogen-rich marlstone that yields more than 15 gallons of oil per ton.

Within the Parachute Creek Member, the 100-foot-thick Mahogany Zone occurs approximately 500 feet below the top of the member (Ref. 3-2). About 40 feet below the top of the Mahogany Zone, the 10-foot-thick Mahogany Bed occurs, the richest bed of oil shale. Part of the Mahogany Zone, including the Mahogany Bed, is the prime target for underground mining.

3.1.3 Mineral Resources

Tract Ua. Samples from Tract Ua show an average thickness of about 55 feet for oil shale with an average Fischer assay yield of 28 gallons of shale oil per ton. Overburden above the Mahogany Zone ranges from 550 to 1,225 feet; the average is about 850 feet. The shale oil resource present in the mining zone is estimated to be 540 million barrels (Ref. 3-3). Current estimates

indicate that about 63 percent of these reserves can be recovered by underground mining methods. Nahcolite is present in the tract only as very thin lenses and small pods. No significant amounts of bituminous sandstone are reported in Tract Ua.

Four deep gas wells were previously drilled on the tract. Three were sealed and abandoned, and one remains capped. This shut-in well flowed at 11,000 cubic feet per day from a zone 3,300 feet below surface. A commercial gas reserve is not anticipated under Tracts Ua and Ub.

Tract Ub. Assayed samples from core holes in Tract Ub also show that the rich zone of shale averages 55 feet in thickness. Overburden above the principal oil shale beds ranges from 300 to 1,250 feet, and the average is about 700 feet. The shale oil resource in the mining zone on the tract is estimated to be about 510 million barrels (Ref. 3-3), 63 percent of which should be recoverable by underground mining. Nahcolite occurs as very thin lenses or beds and small pods in the upper part of the Green River Formation. No commercial oil or gas has been discovered on this tract, and no significant amount of bitumen is known to occur in the sandstone. There are several narrow Gilsonite veins, not commercially recoverable, in the west-central part of the tract (Ref. 3-1).

Off Tract. Off tract, there is a group of about 14 productive gas wells which are located approximately 4 to 5 miles southwest of Tract Ua. Another three productive gas wells are located 1.5 to 3 miles northwest of Tract Ua. Although these wells penetrate the entire thickness of the Eocene strata, the principal productive zone, the Mesa Verde Formation of Cretaceous age, lies considerably deeper in the section.

3.1.4 Water Resources

Tracts Ua and Ub are close to the White River, which will supply water for the project. The mean flow of the White River in this reach is about

700 cubic feet per second, and the weighted average-dissolved-solids concentration is 400 to 500 milligrams per liter. Water could also be obtained from the Flaming Gorge Reservoir by diverting and pumping at a point on the Green River below the Flaming Gorge Dam, about 30 miles northwest of the tracts.

Groundwater occurs in the Bird's Nest Aquifer above the oil shale and in the Douglas Creek Aquifer below the mine zone, but data indicate that the yields are generally small. The groundwater supply does not appear to be large enough to provide a significant supply of water for operations at Tracts Ua and Ub.

3.1.5 Biological Resources

The biotic communities on and near the tracts are of the cold desert shrub type. The vegetation is, for the most part, shrub-dominated. High soil salinity and a preponderance of salt-tolerant shrubs are characteristic of the area. Poplar trees dominate the riparian areas, and juniper trees predominate in the higher elevations at the southern edge of the tracts.

Sheep graze on the tracts in winter and early spring, and some cattle graze in riparian areas in spring and summer. The greatest impact on the area comes from sheep being driven across the eastern portion of Tract Ub. From late summer to early winter, mule deer can be found along the White River riparian habitat and adjacent areas. The tract area is occasionally used for hunting. The only small-game species on the tracts is the cottontail rabbit. Eighteen species of rodents and six species of carnivores have been observed; porcupines are found in riparian habitats, and coyotes, racoons, skunks, bobcats, and badgers are found throughout the tracts.

The tracts support a breeding population of mourning doves, and there are small breeding populations of Canada geese, mallard ducks, and green-winged teal along the White River. Other species of game bird are uncommon or

occur as spring transients. Seventeen species of raptors have been observed on or near the tracts, and 114 bird species other than game birds and raptors have been observed.

Reptiles occur in all four vegetation types in the White River region. Six species of lizards and five species of snakes have been observed on the tracts. Four amphibian species were found on the tracts and in the riparian vegetation along the White River and Asphalt Wash.

Approximately 1,500 species of insects have been collected on or near the tracts. Aquatic macrophytes are nearly absent from the study area. They are probably limited by fluctuating water level and turbidity.

3.1.6 Historical Resources

The Uinta Basin was primarily the homeland of the Ute Indians. The first European contacts were with Spanish explorers and traders from the south. The first year-round white settlement was a trading post established at Fort Rubidoux in 1838. The colonization of the area by Mormon settlers in the latter decades of the 19th century greatly influenced the shaping of the present economy and culture of the Uinta Basin. Although the Wasatch Front was settled earlier, the first Mormons did not enter and explore the Uinta Basin until 1861. The agrarian settlers and the Ute inhabitants were in direct competition for the limited resources available, and an extended period of recurring hostilities ended with the transfer of Utes to the Uinta and Uncompahgre reservations in 1881.

Another important influence on the evolution of the Uinta Basin was the discovery and extraction of the area's rich mineral resources, particularly the discovery of Gilsonite in the late 1800s. Gilsonite mining grew rapidly and hastened the development of the area.

The most important historic feature on or near Tracts Ua and Ub is the Ignatio Stage Station on the White River, north of Tract Ub. This site, one of a series of stage stops along the Uintah Railway toll road that

connected the rail line to Vernal, has been nominated for inclusion in the National Register of Historic Sites; if registered, it will be protected by special regulations and will be eligible for federal funding for preservation or restoration purposes. The remaining structures at the site are good examples of late frontier architecture in this part of the country, but are in poor condition.

3.2 SITE FACILITY LAYOUT

3.2.1 General

The overall layout of WRSP facilities is dictated primarily by the distribution of oil shale in the Tract Ua and Ub sectors, the complex limitations imposed by the rugged terrain, and the lease terms.

The primary objectives of the facility layout are to:

- Maximize overall plant efficiency
- Maximize reuse of facilities throughout all stages of project development
- Ensure ease of access to the site and to the various onsite facilities and equipment
- Establish appropriate locations for water supplies, runoff collection, and shale disposal area, dictated largely by the terrain
- Minimize deleterious effects on the terrain by excavation, construction, and potential floods
- Prevent pollution from products and wastes resulting from oil shale processing

The overall site plan is presented in Figure 3-2. The main process area is centrally located between the Ua and Ub oil shale centroids. Although potentially more favorable terrain locations are available for the process plant, these locations would require more extensive and less efficient facilities and equipment for transporting oil shale from remote sections of the mine and processed shale to Southam Canyon.

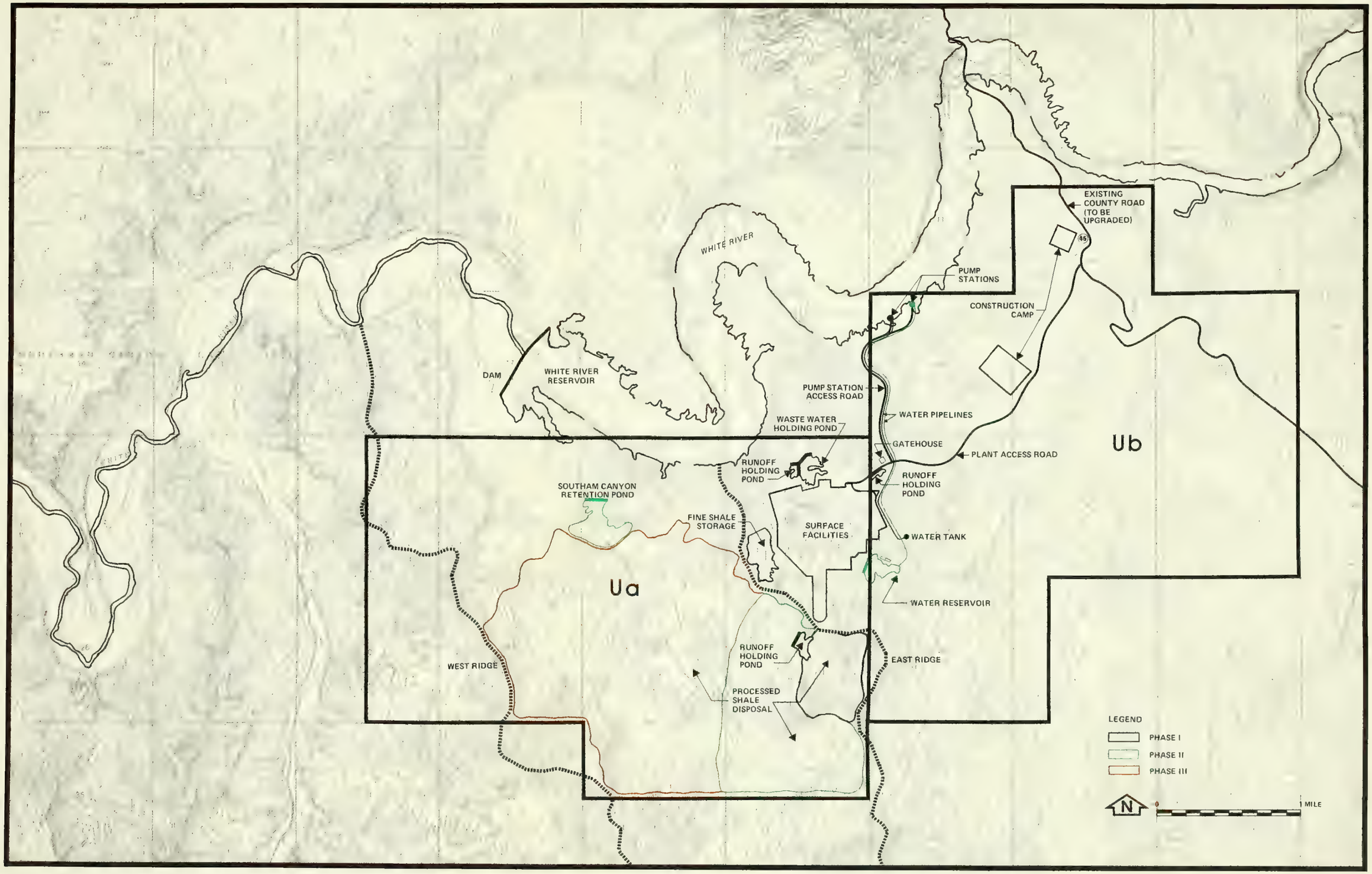


Figure 3-2 OVERALL SITE PLAN

3.2.2 Site Access

Because of the rugged terrain and inadequacy of existing roads in the area, roads must be improved or built both for plant access and on-tract access to the various facilities. During Phase I, a road will be built from the existing road (Highway 45) south to the main plant site. The main plant access roads will be provided, along with on-tract roads branching from the main road to the process plant, water supply pump station, wastewater and storm runoff holding basin, pumping station, and processed shale disposal area. The only additional access required in Phases II and III will branch from the Phase I access road to the entrance of the mine portal and vent shaft sites. A road will be required later for the Tract Ub vent shafts.

The main access road will join existing Highway 45 at a point 0.8 mile south of the White River. From that point, access from the north will be provided by Highway 45, which will be upgraded and paved from that point to Bonanza during Phase I construction. A new bridge across the White River will also be required if the White River Dam is constructed by the state of Utah. WRSP is consulting with Uintah County concerning the alignment and construction of this primarily off-tract road.

3.2.3 Site Preparation

Site preparation plans for surface facilities have been developed to minimize disturbed areas and earthwork and to establish an efficient, functional plan.

Site work for all drainage impoundment structures will involve removing weak soils from areas proposed for onsite construction. These soils will be used for revegetation or in constructing certain parts of these dams. Most of the material for these dams will come from the area to be inundated by the stored water.

Construction activities in each stage will disturb only limited areas other than those shown. These other areas will be for material storage and will be located outside temporary work areas.

3.2.4 Water Supply

The pumping station will be built near the south bank of the White River, and a pipeline will be laid from the river to the onsite plant reservoir. From the plant reservoir, two pipelines will be laid, one for the process plant and one for the processed shale disposal area. The onsite reservoir dam, constructed early in Phase II, will be located above the plant to minimize the need for additional pumping. During Phase I, water will be supplied directly to a storage tank in the process plant to eliminate the need for a plant reservoir.

3.2.5 Mine Shaft Locations

Parameters considered when locating the Phase I shafts were the Tract Ua and Ub centroid, surface topography, prevailing wind direction, secondary crusher location, conveyor angles, and future expansion. Natural topography enables the friction hoists to be mounted over the shafts at the surface elevation.

3.2.6 Oil Shale Handling

The raw oil shale will be hauled to the underground primary and secondary crushers; it will then be transported to the surface via vertical shafts in Phase I and also via conveyors in the mine declines in Phases II and III. The most efficient removal of oil shale requires the declined entries to be located close to the retorting facilities.

At the portal, the oil shale will be transferred from the declined conveyors to the aboveground conveyors. These two aboveground feeder conveyors will intersect with the main conveyor, which will transport the crushed shale to a storage silo, and then to the retorts. Adjacent to these conveyors will be a stockpile for crushed shale. This stockpile will be used in Phases II and III for buffer storage of shale to balance differences in daily operating rates of the process plant and the mine.

3.2.7 Process and Support Facilities

The process area plot plan is presented in Figure 3-3. The proposed processing plant and its supporting facilities will be built near the center of Tracts Ua and Ub and will allow oil shale to enter the southwest corner of the plant from the mine production shafts, storage silos, and stockpiles. The site layout is constrained by the terrain and the need for certain facilities to be close to other related facilities. Generally, the retorting facilities will be located in an L-shaped area covering the center and northwestern edge of the site plan. The shale oil upgrading plants will be at the southeastern and north-central edges of the retorting areas.

Storage facilities for products, by-products, intermediates, and raw materials are spread over the ridge of hills on the eastern edge of the site. The administration, warehouse, fire house, and other buildings are concentrated in the northeast quadrant of the site adjacent to the site access road that enters the plant at the northeast corner. A raw water reservoir at the southeast corner and a wastewater reservoir at the northwest corner complete the onsite facilities.

Phase I. The surface facilities will be centered on two retorts (one Union B and one Superior) together with the necessary raw shale oil processing and upgrading units. The retorts will be capable of processing 24,600 TPSP of shale to produce 15,930 BPSD of raw shale oil. The upgrading plant will convert this to 14,840 BPSD of net synthetic crude product.*

Supporting facilities will be sized for Phase I loads only, but will be designed for cost-effective expansion to Phase II and III capacities. The facilities include steam generation; sulfur and ammonia recovery and storage; crude and syncrude storage; raw and wastewater treatment; runoff

*2,150 BPSD will be consumed as liquid fuel in the plant. (See Table 4-9.)

control and storage; and administration, control, laboratory, warehouse, and other buildings.

Phases II and III. During Phases II and III, the retorting and upgrading facilities will be expanded in two stages to process 176,740 TPSD of raw shale and produce 106,230 BPSD of net syncrude product. All support facilities will be expanded in proportion to the requirements set by the mining, retorting, and upgrading capacities. Furthermore, facilities will be added to generate electrical power.

3.2.8 Processed Shale Disposal

As shown in Figure 3-2, the processed oil shale will be disposed of in the Southam Canyon area immediately adjacent to the main process area. This canyon provides a suitable fill area for the processed shale and a location for a retention dam that will prevent runoff from entering the White River.

During Phase I, a conveyor will carry processed shale to a bin southwest of the retorts for removal by truck to Southam Canyon. During Phases II and III, processed shale will be taken from the process plant on conveyor southwestward, to a location near the edge of Southam Canyon for optimal placing in Southam Canyon.

LEGEND:

		PHASE I	PHASE II	PHASE III
PROCESS FACILITIES				
1	COARSE SHALE RETORT: SUPERIOR	•	•	•
2	COARSE SHALE RETORT: UNION B	•	•	
3	FINE SHALE RETORT: TOSCO		•	•
4	H_2 PLANT	•	•	•
5	HTU PLANT	•	•	•
6	PROCESS WASTE WATER TREATMENT	•	•	•
7	SULFUR PLANT	•	•	•
MINING AND MATERIAL HANDLING AND OTHER FACILITIES				
A	GATEHOUSE	•		
B	HAZARDOUS WASTE DISPOSAL SITE	•	•	•
C	RAW SHALE STOCKPILE	•	•	•
D	FINE SHALE STORAGE	•		
E	EXPLOSIVES STORAGE	•	•	•
F	PARKING LOT	•	•	
G	MULTIPURPOSE BUILDING	•		
H	LABORATORY BUILDING	•	•	
J	WAREHOUSE	•	•	
K	FIREHOUSE		•	
L	CHANGE ROOM		•	
M	ADMINISTRATION BUILDING		•	
N	HELICOPTER PAD	•		
O	CAFETERIA		•	
P	MINE SERVICE BUILDING	•	•	
UTILITIES				
I	BOILER AND POWER PLANT	•	•	•
II	SUBSTATION	•	•	•
III	COOLING TOWER	•	•	•
IV	WASTEWATER TREATING (NON PROCESS)	•	•	•
V	SEWAGE TREATMENT PLANT	•	•	•
VI	RAW WATER TREATMENT PLANT	•	•	•
VII	TRUCK LOADING	•		
VIII	SHALE OIL PUMP STATION	•	•	•
IX	FLARE	•	•	•
Xa	TANK: SHALE OIL PRODUCT	•	•	•
Xb	TANK: BY-PRODUCT	•	•	•
Xc	TANK: RAW SHALE OIL AND INTERMEDIATE PROCESS	•	•	•
Xd	TANK: UTILITY	•	•	•
XI	RUNOFF HOLDING POND	•		
XII	WASTEWATER HOLDING POND	•		
XIII	WATER RESERVOIR		•	
XIV	SULFUR STORAGE PAD	•	•	•

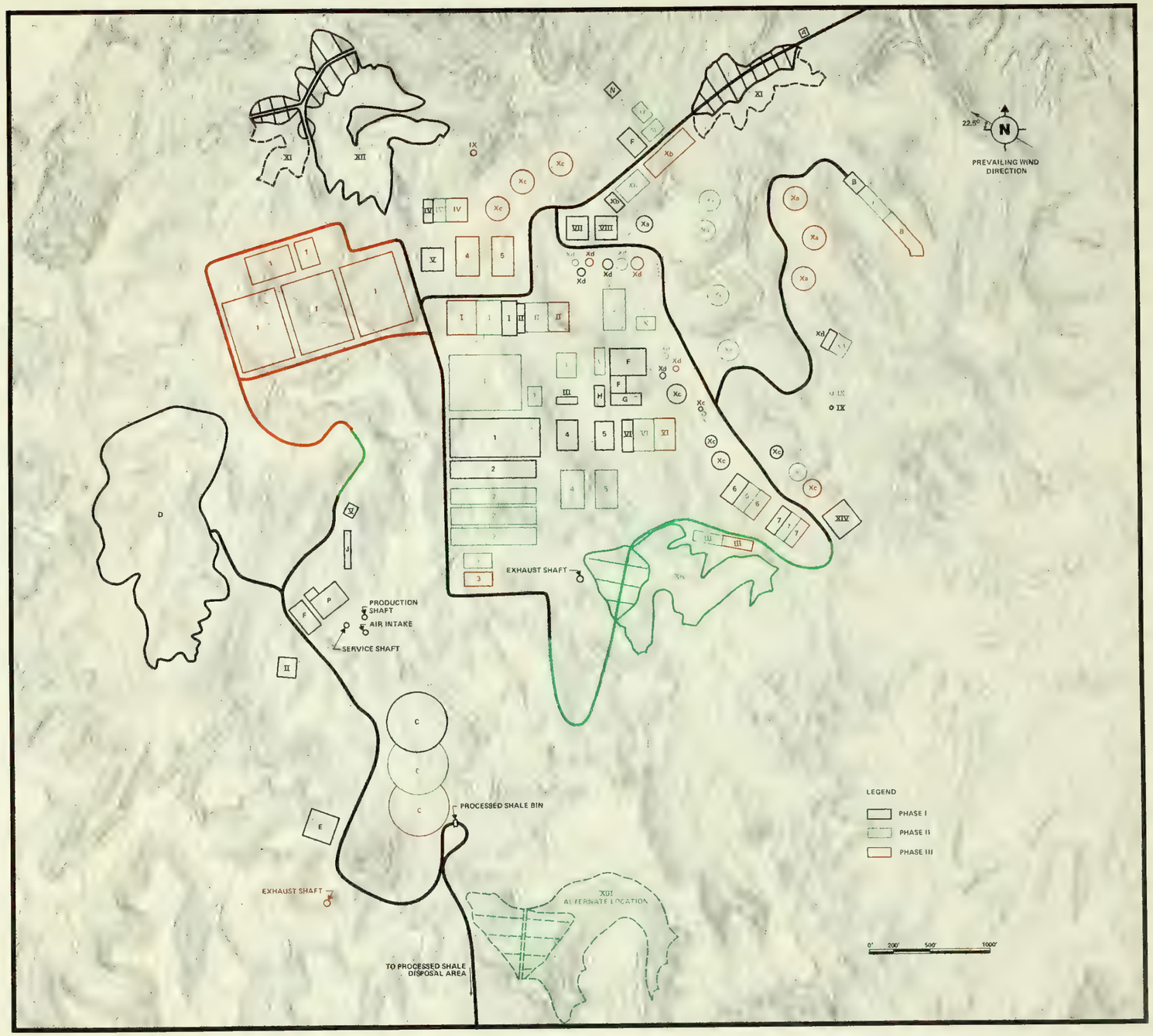


Figure 3-3 PROCESS AREA PLOT PLAN

REFERENCES — SECTION 3

3-1 W. B. Cashion, "Geology and Fuel Resources of the Green River Formation, Southern Uinta Basin, Utah, and Colorado," Professional Paper 548, U.S. Department of the Interior, Geological Survey, Washington, D.C., 1967.

3-2 Preliminary Environmental Statement, U.S. Department of the Interior, Washington, D.C., June 1971.

3-3 Final Environmental Statement for the Prototype Oil Shale Leasing Program, U.S. Department of the Interior, Washington, D.C., 1973.

Section 4

PROCESS DESCRIPTION

The WRSP plan for recovering oil from shale consists of staged development of mining, feed preparation and material handling, retorting, and gas and oil processing in three phases. Phase I is a modular program of relatively small scale. During Phase I, up to 27,330 tons per stream day (TPSD) of shale rock will be mined and processed to yield up to 14,840 barrels per stream day (BPSD) of net synthetic crude oil product. The knowledge gained during Phase I will permit the refinement of those techniques best suited to process shale from Tracts Ua and Ub on a larger scale. Subsequently, Phases II and III will mine 93,460 and 176,740 TPSD of shale and produce approximately 57,190 and 106,230 BPSD of net synthetic crude oil product, respectively.

4.1 MINING

The commercial oil shale mine to be developed on Tracts Ua and Ub is designed in three phases of production capacity: Phase I up to 27,330 TPSD, Phase II up to 93,460 TPSD, and Phase III up to 176,740 TPSD, Figure 4-1 presents this phased oil shale production capacity. An underground room-and-pillar mining method has been selected as the most economical and suitable way of extracting the oil shale. The assumed average grade of shale to be mined is 28 gallons per ton.

The geology of the proposed mining zone has been described in three other reports, so it is not summarized here. For detailed information on mine geology, refer to Preliminary Rock Mechanics Report (Ref. 4-1), Geologic Exploration Program Report (Ref. 4-2), and Geophysical Logging Report (Ref. 4-3).

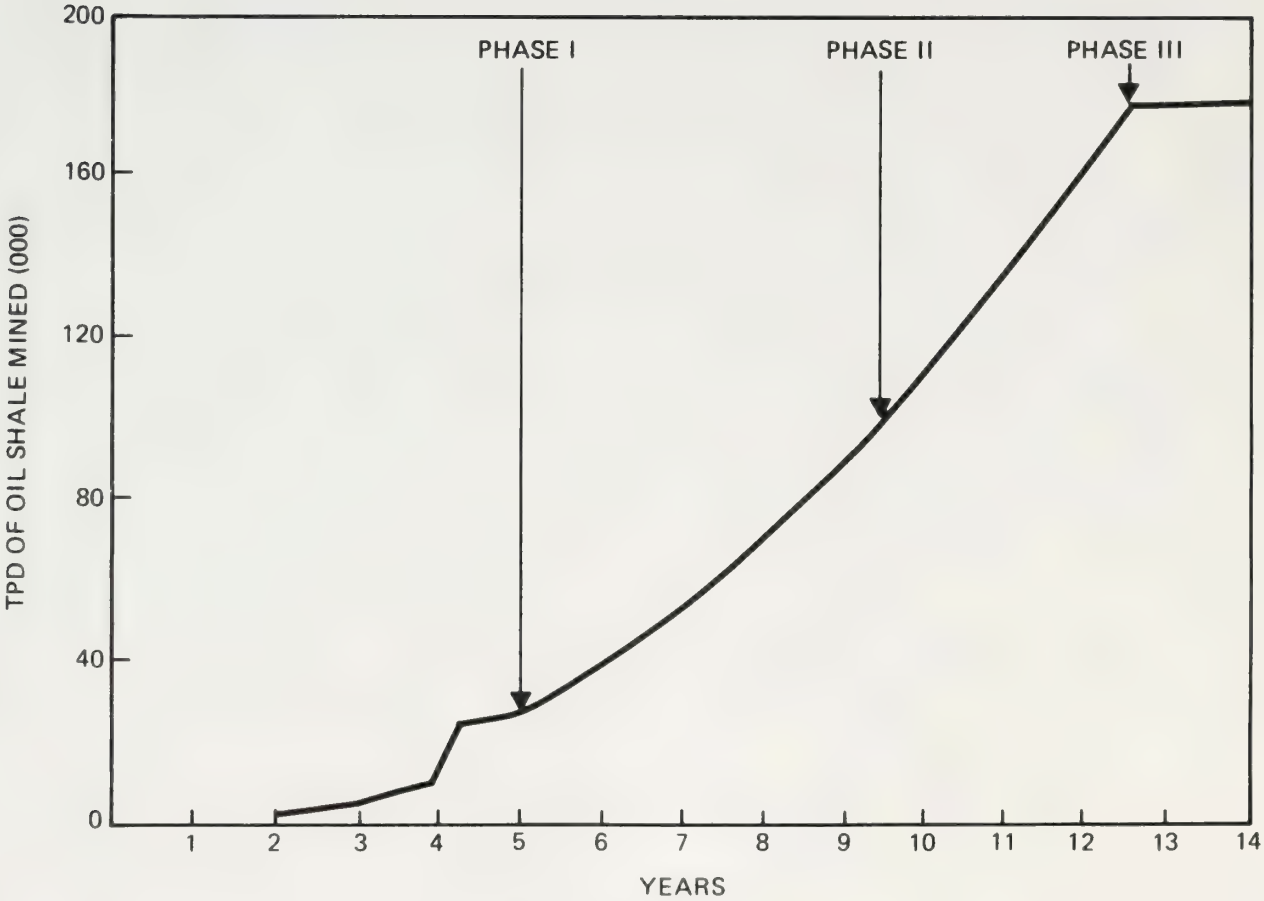


Figure 4-1 MINE PRODUCTION

4.1.1 Phase I

The goal of the two-retort operation in Phase I is to bring into production a mine capable of providing up to 27,330 TPSD of oil shale. A production shaft, service shaft, and air exhaust shaft, each 28 feet in diameter, will be sunk near the Tract Ua-Ub centroid. The ventilation system will provide 2,000,000 cfm of air to the mine operation.

The 28-foot-diameter production and service shafts will also serve as ventilation air intakes. Shaft diameters were dictated by ventilation requirements and breakdown dimensions of underground equipment. A third shaft, also 28 feet in diameter, will serve as the exhaust air course, with shaft size dictated by ventilation requirements.

Preproduction mine development will consist of driving entries to mining areas, and to shop, warehouse, primary and secondary crushing, and ore handling facilities. All associated facilities, including ventilation and utilities distribution, will be completed during this development phase. Initial mine development will proceed in an easterly direction.

Mine site surface construction will include hoisting facilities, fan installation, a changehouse, an office, a parking lot, shops, explosives magazine, and storage yard. All surface shaft and production areas will be adequately fenced for security and safety reasons.

These developmental activities will take 4 years to complete, culminating in a mine production rate of 27,330 TPSD. Panels will be developed and mined east of the shaft locations during this phase. Figure 4-2 shows the shaft and panel layout for the Phase I operation.

4.1.2 Phase II

The Phase II operation will require a mine production rate up to 93,460 TPSD. Development to reach this level of production will continue north-

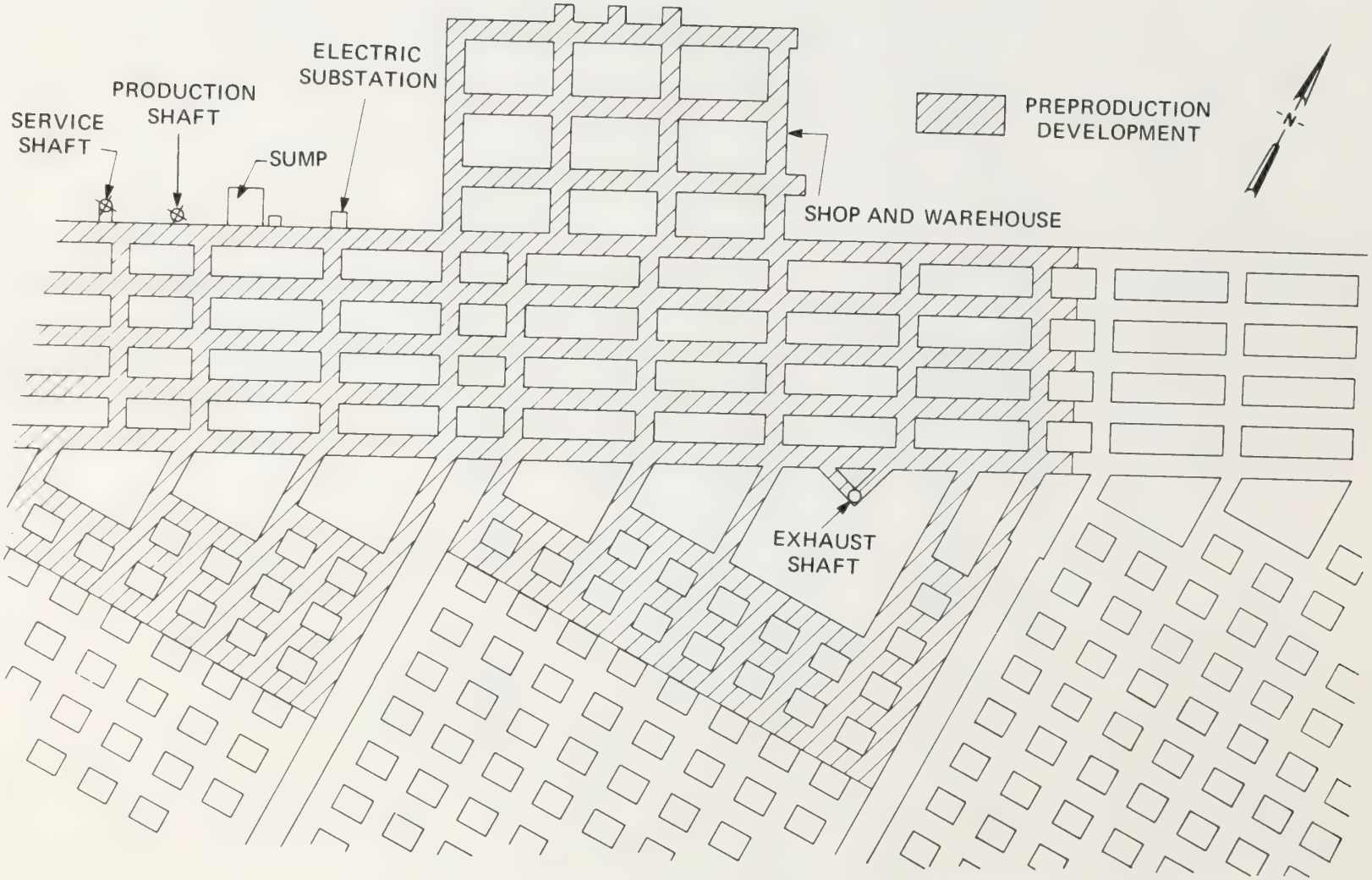


Figure 4-2 PHASE I MINE PLAN

east toward the centroid of Tract Ub. Presently planned is an incline between the surface and the mining horizon to serve as a beltway for moving the additional Phase II tonnage to the surface. The Phase I production shaft will continue to be used for hoisting up to 30,000 TPSD, and the Phase I service shaft will continue to serve as a man-and-materials hoisting facility. Two 34-foot-diameter ventilation shafts will be sunk in the Tract Ub area to provide up to 4,000,000 cfm of additional air for the expanded operation. Additional underground shop and warehouse facilities will be constructed near the centroid of Tract Ub to serve as a satellite shop area for Phase II mining activities. Minor maintenance will be done near the working panels. Surface structures will be located to conform with the surface topography as well as to fit the pattern of underground workings.

During Phase II, panel mining will progress outward from the Ua-Ub centroid, and mining will proceed concurrently within four or five panels. The ore produced will pass through primary and secondary crushers before being conveyed or hoisted to the surface for tertiary crushing (for the Union B retort) and retorting. The construction and mine development stage of Phase II operations will last approximately 4 years. Development ore will feed the commercial stage retorts.

4.1.3 Phase III

Phase III operations will increase the production rate to an ultimate 176,740 TPSD. An inclined beltway will be driven westward from the plant area to the mining zone and, from there, on toward the centroid of Tract Ua. Two 34-foot-diameter shafts will be sunk outside the Southam Canyon drainage system to allow delivery of up to 4,000,000 cfm of additional ventilating air to the mine. These shafts will not be near the Tract Ua centroid, which lies in Southam Canyon, because that area will be used for processed shale disposal. The Phase I production and service shafts will continue to be used during Phase III, as will the Phase II decline and ventilation shafts.

The general mine layout for Phases I, II, and III is shown in Figure 4-3. The location of shafts and incline conveyor portals are shown on the mine site plan in Figure 4-4.

All mining activity will follow the same pattern as in Phase II. Production is projected to continue at the 176,740 TPSD rate until the reserves are depleted. Further details on the mine are available in the White River Shale Detailed Development Plan (Ref. 4-4).

4.2 FEED PREPARATION AND MATERIAL HANDLING

The process of preparing the mined oil shale for retorting requires facilities for crushing and screening the raw shale, and for feeding it to the retorts. There will be three stages of crushing operations before retorting; primary and secondary crushing will take place underground, and tertiary crushing will take place on the surface near the Union B retorts. The type of retort used will determine the size to which the oil shale must be crushed and screened. Covered conveyors will transport oil shale to storage silos, tertiary crushers, the stockpile area, retort silos, and retort feed hoppers; they will also move the processed shale to the disposal area. In addition, covered conveyors will transport fines to retort feed silos, retorts, and to and from the fines storage stockpile.

Secondary crushed oil shale will be stockpiled on the surface near the tertiary crushing plant to ensure uninterrupted operation of the tertiary crusher and continuous feed to the retorts. The underground mine haulage system and primary and secondary crushing operations will be interdependent. If the primary or secondary crusher is shut down, haulage from the mine will be stopped; the tertiary crusher and the retorts will then be fed from the stockpile.

4.2.1 Feed Specification

The oil shale will be broken into pieces smaller than 4 inches (a size suitable for the Superior retort) in the primary and secondary crushing

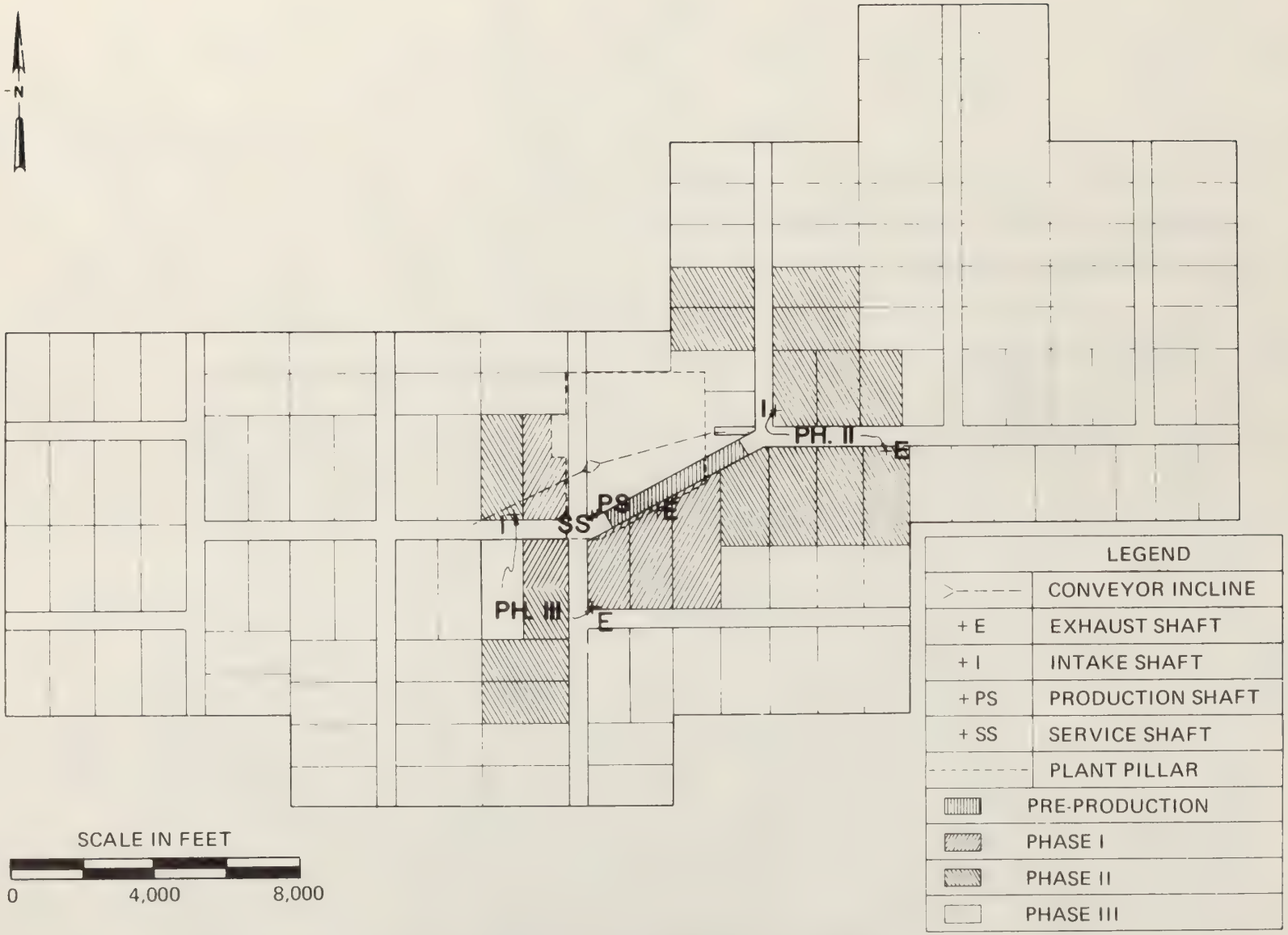


Figure 4-3 GENERAL MINE LAYOUT, ALL PHASES

steps underground. On the surface, further crushing and screening steps will reduce this ore to appropriate sizes for the Union B retort. The Superior and Union B retorts will require feed material sized plus ¼ inch by minus 4 inches and plus ¼ inch by minus 2 inches, respectively; fines-type TOSCO II retorts will process the fines smaller than ¼ inch. The operations required to produce such a suitable feed are described in the following paragraphs for the three project phases.

4.2.2 Phase I Operations

Phase I retorting will require 27,330 TPSD of shale. The operations required to provide this shale to the retorts in Phase I include primary and secondary crushing, stockpile and reclaim, tertiary crushing and screening, material handling, and dust control. A material handling flow diagram for Phase I is shown in Figure 4-5.

Primary Crushing. Both stationary and movable crusher installations will be provided for underground primary crushing of oil shale. Skidmounted, feed-breaker-type crusher units will be used for crushing shale excavated from upper-bench and development entry headings. The 40-inch by 66-inch movable units will be located close to the mining faces. Permissible load-haul-dump units will haul shale from the mining areas to the crusher installations. Minus-12-inch material produced by the crushers will be transported to a secondary crusher installation on extendable 48-inch wide conveyor belts.

A crusher station located near the production shaft will be equipped with a stationary, 48-inch by 72-inch toothed single-roll primary crushing unit. The crusher will be capable of reducing up to 1,000 tons per hour of scalped feed (minus 48 inch by plus 12 inch) to minus 12 inches.

Trucks hauling from lower-bench mining areas will supply shale to the primary crushing complex. Minus-12-inch material passing through a vibrating

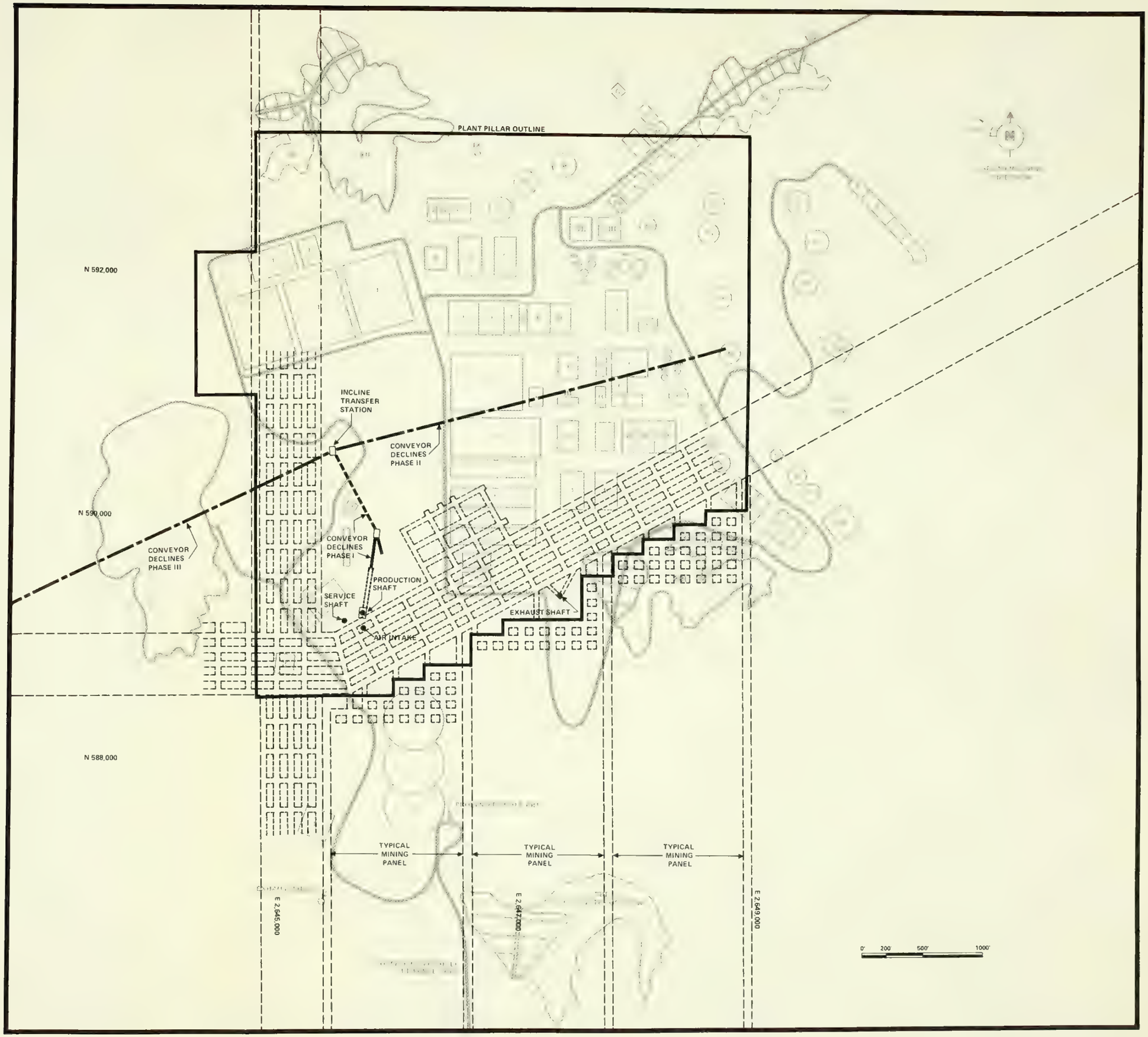
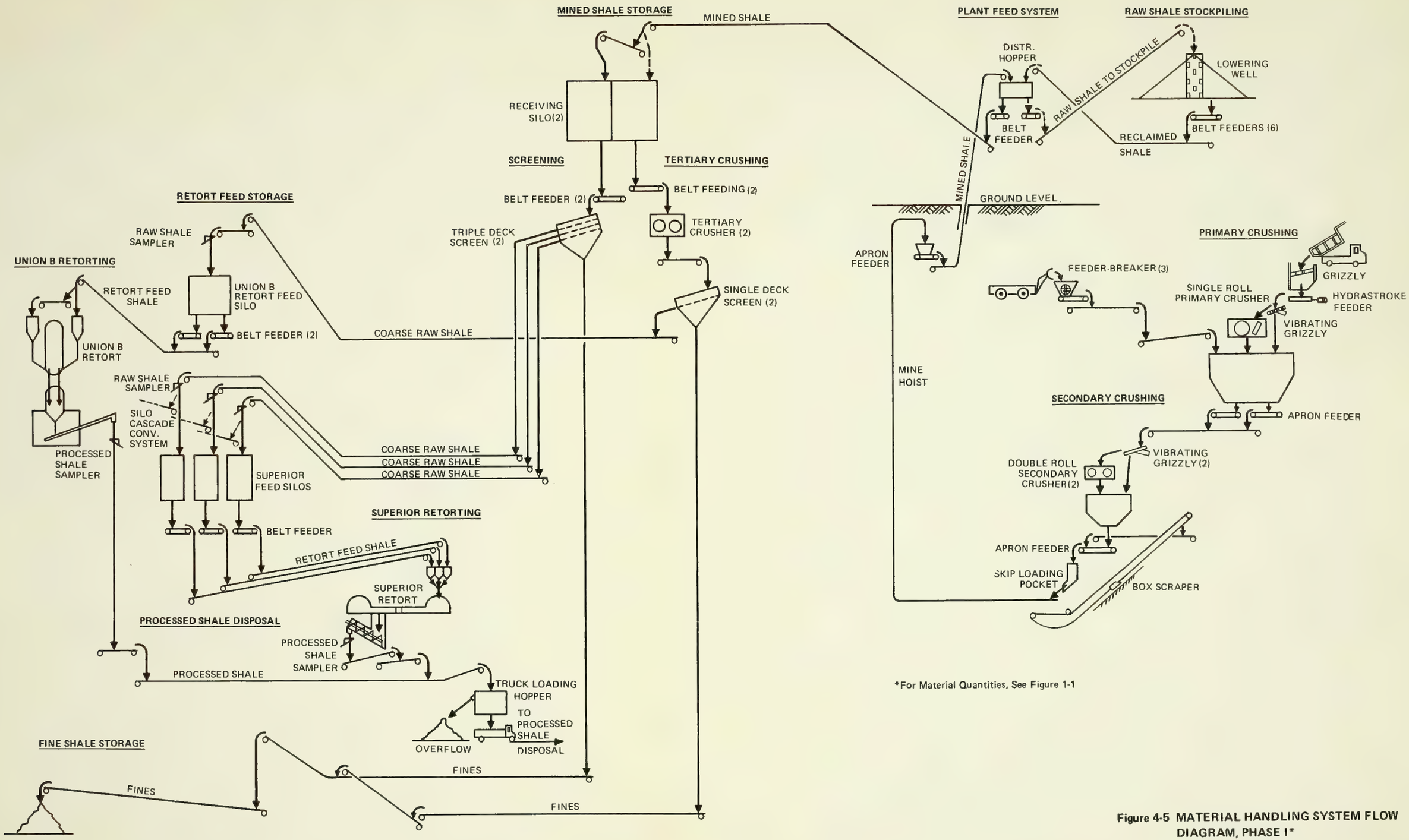


Figure 4-4 MINE SITE PLAN



*For Material Quantities, See Figure 1-1

Figure 4-5 MATERIAL HANDLING SYSTEM FLOW DIAGRAM, PHASE I*

grizzly and the minus-12-inch crusher product will pass through a surge bin and subsequently be conveyed to the nearby secondary crusher installation.

Secondary Crushing. The secondary crushing station will be underground near the production shaft. The station will be equipped with two 48-inch by 60-inch toothed, double-roll crushers capable of crushing a minus-12-inch scalped feed material to a minus-4-inch product at a rate of up to 1,200 tons per hour each. Feed material will come from the primary crusher station located nearby and from movable feeder-breaker units located in the upper-bench and development entry mining areas. After crushing, the minus-4-inch product will pass into a storage bin for eventual skip loading and transport to surface.

Dust Control. Dust generated in the primary crusher areas will be controlled by suppression systems. Mist sprays of water with an added surfactant (if required) will be used at feeder, grizzly, and crusher discharge points. The small amount of dust that escapes these systems will be removed from the area by normal ventilation and subsequently discharged into a mine ventilation exhaust stream. Because of the large openings in the mine and low ventilation current velocities, dust will not be transported over long distances but will settle out. To further ensure reduced velocities for settling dust in return air circuits, exhaust air will be channeled through mined-out production panels.

Dust generated by the secondary crusher and ancillary vibrating grizzlies and feeders will be controlled by a baghouse collector system of 5,000 scfm. The collected dust will discharge from the collector into a dust conditioner and moistener, loaded once per shift into a truck, and hauled once a day to a mined-out section of the mine for ultimate disposal.

Stockpile and Reclaim. After being hoisted to the surface, secondary crushed material (minus 4 inches) will be conveyed to the storage silos

or a conical stockpile near the storage silos. The raw oil shale stockpile will be in the open and of an appropriate size to support retort operations for about 18 days. (The present estimate is approximately 500,000 tons.) A stockpile lowering well will suppress dust during the stockpiling operation.

Oil shale will be drawn from the stockpile by belt feeders onto a belt conveyor within a reclaim tunnel and transported to the storage silos. The coarse shale stockpile and reclaim system provides surge capacity between the mine and crusher facilities.

Storage Silos, Screening, and Tertiary Crushing. For the Superior retort, coarse (minus 4 inch) oil shale is reclaimed by a belt feeder from the storage silos and is conveyed to vibrating screens. The triple-deck vibrating screens, 8 feet by 20 feet, produce four product sizes - minus 4 by plus 3 inches, minus 3 by plus 2 inches, minus 2 by plus ¼ inch, and minus ¼ inch fines. The three larger products are transported by conveyors to three Superior feed silos. The minus-¼-inch fines are transported by belt conveyors for compaction in the fines storage stockpile. The three product streams are sampled by a continuous sampling system before entering the Superior feed silos. The products are reclaimed from the Superior feed silos by belt feeders onto three retort feed belt conveyors.

For the Union B retort, belt feeders reclaim the minus-4-inch oil shale from the storage silos and deliver it to the 30-inch by 60-inch tertiary roll crushers, which reduce the shale to minus 2 inches. Belt conveyors transport the crusher product to single-deck vibrating screens, 8 feet by 20 feet, which screen out the minus-¼-inch fines. Fines are then conveyed to the fines storage stockpile. The minus-2-by-plus-¼-inch product is transported by belt conveyor to the Union B retort feed silo. The shale is sampled before entering the silo and is reclaimed from the silo by belt feeder onto a retort feed belt conveyor.

Dust will be controlled at conveyor transfer points by full enclosure and wet dust suppression and all conveyor belts will be covered. Baghouse dust collectors will be used at the silos and at crushing and screening plants.

Processed Shale Disposal. At the Union B retort outlet, the processed shale will pass through a water seal and will be deposited onto the processed shale disposal conveyor at a temperature of about 200F. Processed shale will be sampled at each retort before being deposited on the disposal conveyor, which will transport the shale to the truck loading facility. Water sprays will be provided on the disposal conveyor for saturating the spent shale.

Conveyor Construction. All conveyors will be electrically driven and will be provided with the required safety devices. All surface conveyor belts carrying raw and processed shale will be enclosed and of dust-confining construction. Conveyors will be routed to cover minimum distances with maximum permissible slopes. Roadways will be constructed along conveyor routes to facilitate construction and provide maintenance access.

4.2.3 Phase II Operations

The Phase II retorting operation requires up to 93,460 TPSD of oil shale. Phase I facilities will continue to operate during Phase II. A material handling flow diagram for Phase II is shown in Figure 4-6.

Primary Crushing. Three stationary primary crushers will be needed for the Phase II mining operation. Besides the initial single-crusher installation at the production shaft, a second primary crushing complex will be needed for reducing lower-bench ore. It will have two 48-inch by 72-inch toothed single-roll crushers and will be located near the base of a conveyor incline to surface. A total of eight skid-mounted, feeder-breaker-type primary crusher units will be located in upperbench and development mining areas. The minus-12-inch product from all of the primary crushing units

will be conveyed to bins located ahead of either of two secondary crusher installations. Auxiliary equipment will include dust suppression systems as described for Phase I.

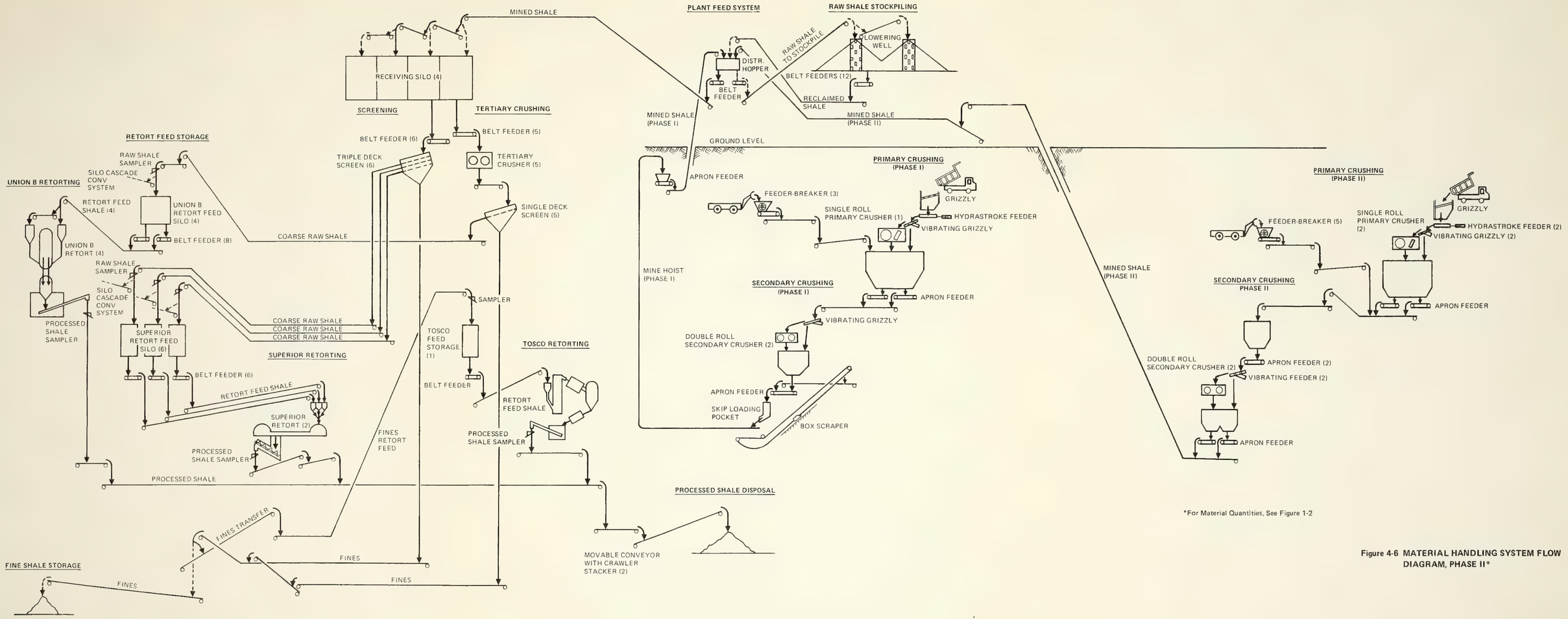
Secondary Crushing. A crushing installation will be constructed near the base of a conveyor incline to augment the secondary crushing facilities established for Phase I, and it will have two 48-inch by 72-inch toothed double-roll crushers. Minus-12-inch feed for the crushers will be drawn from a 750-ton bin and scalped over vibrating grizzlies. Underflow from the grizzlies and minus-4-inch product from the crushers will be discharged into a 2,500-ton storage bin for subsequent conveying to surface.

Auxiliary equipment will include dust collection systems as described for Phase I.

Stockpile and Reclaim. For Phase II, a second conical stockpile will be added, and the stockpile feed and reclaim conveyor systems will be extended. The total Phase II stockpile capacity will be 1,000,000 tons. A stockpile lowering well will suppress dust during stockpiling operations in Phase II. The stockpile will be able to support retort operations for about 11 days.

Dust Control. Dust control devices and procedures in Phase II will be the same as those in Phase I, except baghouse capacity will be increased to to 15,000 scfm.

Storage Silos, Screening, and Tertiary Crushing. For Phase II, the Phase I system will be expanded by adding more storage silos, screens, and tertiary crushers. The existing conveying system capacity will be upgraded by extending the conveyors, increasing belt speeds, and installing new drives. Retort feed silos and retort feed conveyors will be added to the Superior, Union B, and TOSCO retorts.



*For Material Quantities, See Figure 1-2

Figure 4-6 MATERIAL HANDLING SYSTEM FLOW DIAGRAM, PHASE II*

Processed Shale Disposal. The processed shale from the TOSCO retort will be water quenched to 200F, sampled, and deposited on the processed shale disposal conveyor in a similar manner to that for the Superior and Union B units described in Phase I. Instead of truck transport (Phase I), the processed shale disposal conveyor system will be extended to the disposal site.

4.2.4 Phase III Operations

Phase III retort operation will require 176,740 TPSD of shale. The retort plant will use identical equipment to that installed for the Phase II plant and will operate on the same process flow. (Refer to Figure 4-7 for a diagram of material handling flow in Phase III.)

Primary and Secondary Crushing. Crushing and material handling facilities will be added to increase the mine production capacity in Phase III. Primary crushing will use five toothed single-roll crushers at three locations and 14 feeder-breakers located in various upper-bench and entry mining areas. Secondary crushing will use six toothed double-roll crushers at three centralized locations. Auxiliary equipment will include grizzlies, feeders, and dust control equipment, as described for Phases I and II.

Stockpile and Reclaim. For Phase III, a third conical stockpile will be added to the Phase II system, and the stockpile feed and reclaim conveyor systems will be extended. The total Phase III stockpile capacity will be 1,500,000 tons. A stockpile lowering well will suppress dust during stockpiling operations. The stockpile will be able to support retort operations for about 8 days.

Dust Control. Dust control devices and procedures in Phase III will be the same as those in Phases I and II, except that baghouse capacity will be increased to 30,000 scfm.

Storage Silos, Screening, and Fines Reclaim. For Phase III, a new system of storage silos and screening facilities will be constructed. This system will reclaim feed from the mine via the distribution hopper (as in Phases I and II) or reclaim feed from the stockpile via the distribution hopper. The new system will start at the distribution hopper discharge, and a conveyor will be added to transport shale from the distribution hopper to the Phase III storage silos, screening plant, Superior and TOSCO feed silos, and the retorts.

A new reclaim system will be added to convey fines from the fines stockpile to the TOSCO retorts.

Processed Shale Disposal. The Phase III system will be an extension of the Phase II system.

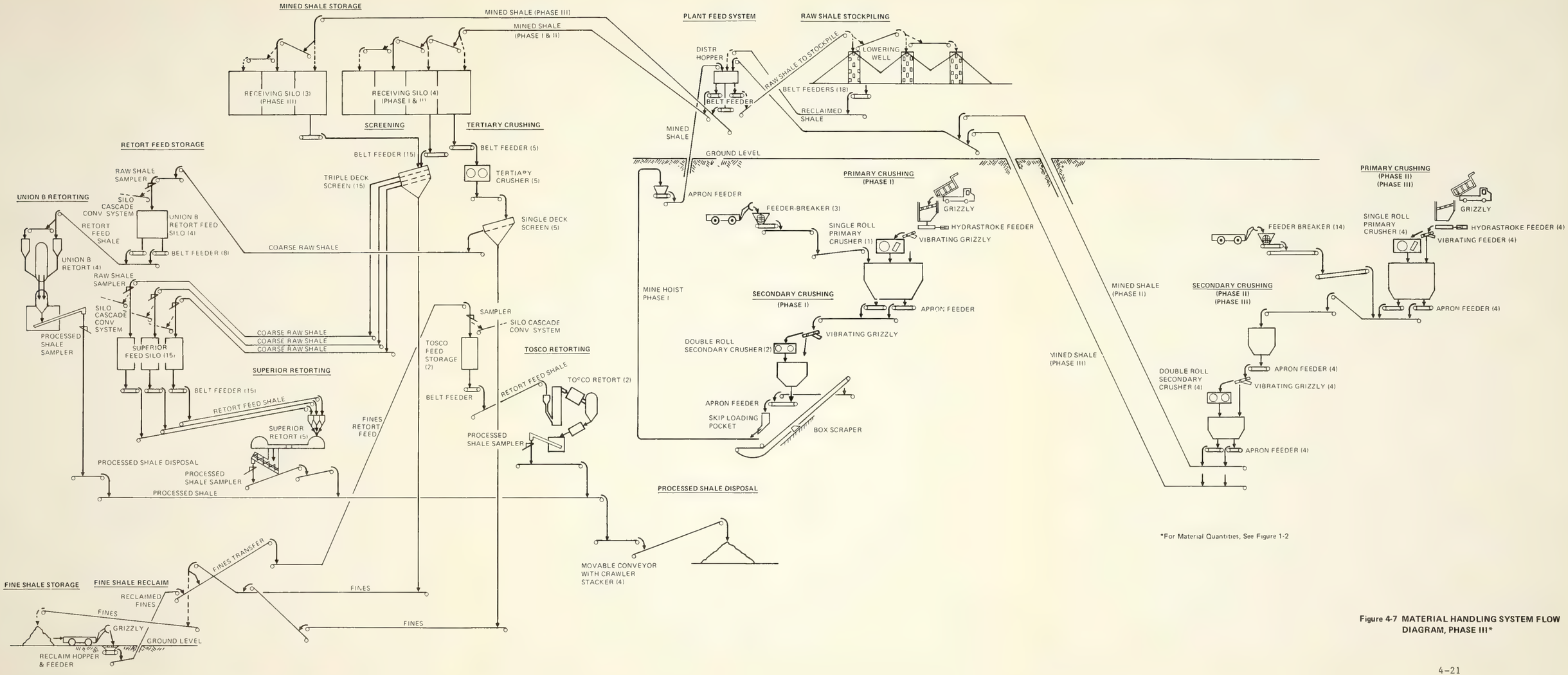
4.3 RETORTING

Discussed below are the retorting operations involved in a modular development program proceeding in three phases to a commercial-size shale oil facility. Retorting equipment and products proposed for the Phase I two-retort operation are discussed, as are the ultimate products and types of retorts that will be needed for a full-scale commercial plant in Phases II and III. Flow diagrams and material balances associated with retorting operations in each of the three phases are included.

4.3.1 General Retorting Description

The retorting operations are implemented in three phases of production capacity:

- Phase I: Development operations producing up to 15,930 BPSD of raw shale oil:
  - One 11,600 TPSD Union B indirect-heat (IH) retort
  - One 13,000 TPSD Superior direct-heat (DH) retort



*For Material Quantities, See Figure 1-2

Figure 4-7 MATERIAL HANDLING SYSTEM FLOW DIAGRAM, PHASE III*

- Phase II: Commercial operations producing 60,940 BPSD of raw shale oil through the addition of:
  - Three 11,600 TPSD Union B retorts
  - One 25,000 TPSD Superior retorts
  - One 9,345 TPSD TOSCO II fines retort
- Phase III: Commercial operations producing 113,950 BPSD of raw shale oil through the addition of:
  - Three 25,000 TPSD Superior retorts
  - One 9,155 TPSD TOSCO II fines retort

The objective of Phase I is to evaluate and develop to commercial status a circular-grate DH Superior retort and a vertical-flow IH Union B retort. Fines produced during Phase I will be stockpiled for recovery and retorting in Phase III.

The proposed use of three different types of retorts in Phases II and III — direct heated, indirect heated, and fines type — is based on specific process needs coupled with the requirement for high operating and thermal efficiency.

Table 4-1 presents material balances for each phase of the retorting program, representing the combined inputs and outputs for all retorts.

4.3.2 Circular-Grate Direct-Heated Superior Retort

The circular-grate direct-heated (DH) Superior retort has four significant features that distinguish it from other retorting technologies:

- Fixed Bed with Circular Grate. The shale is processed as a fixed bed resting on a donut-shaped circular grate, which rotates horizontally about its central axis. Thus the shale and the grate travel together through various processing zones within a fixed hood that overhangs the grate.

Table 4-1

RETORTING MATERIAL BALANCE[a]

Component	Phase I		Phase II		Phase III	
	TPSD	BPSD (MMSCFSD)	TPSD	BPSD (MMSCFSD)	TPSD	BPSD (MMSCFSD)
Retort Feed Shale (Wet)	24,600		93,456		176,740	
Air to DH Retorts	2,856	(74.7)	8,285	(216.8)	24,572	(643.1)
Water Makeup	408		1,184		3,512	
Fuel Oil/Upgraded Shale Oil[b]	15	102	43	294	127	687
Total In	27,879		102,968		204,951	
Low-Btu Gas	3,315	(87.4)	9,617	(253.7)	28,523	(752.6)
High-Btu Gas	222	(7.9)	1,092	(37.6)	1,282	(43.1)
Raw Shale Oil (Dry)	2,557	15,926	9,792	60,944	18,206	113,952
Water (in Liquid Streams)[c]	503		1,880		3,679	
H_2S (in Amine to Regen.)	12		60		71	
CO_2 (in Amine to Regen.)	17		84		98	
$CO_2 + NH_3$ (in Water to Treat.)	1		9		15	
Processed Shale (Dry)	20,871		79,335		149,818	
Water in Processed Shale	379		1,099		3,259	
Total Out	27,879		102,968		204,951	

(a) Gas and oil quantities shown are before consumption as fuel and feedstocks.
(b) Retorting requirements only.
(c) Water out is greater than water in due to retort water production and natural moisture in feed shale.

- Cross-Bed Gas Flow. Gas flow is vertically through the bed (cross flow) rather than cocurrent or countercurrent.

- Direct Heat with Combustion both Internal and External to Retort. While nominally a direct-heat retort, since all heat transfer is by combustion-product gases, the Superior retort generates heat by combustion of recycle gas in a burner external to the retort as well as by combustion of coke on processed shale.

- Integrated Gas Washing Step. The retort gas is produced at relatively low sulfur contents, due to using a water-wash internal to the retort.

Mechanical Description. A general layout of the Superior retort is shown in Figure 4-8. The primary flow streams are shown schematically in Figure 4-9, where the successive processing zones of the circular grate are shown as a single line in series for ease of illustration.

The significant items of equipment include the retort itself, the product cooling and quench system, electrostatic precipitators for oil mist and solids recovery, blowers for transport of air, recycle gas and product gas, the inert gas system, the retort water systems, and the conveyors for feed shale and processed shale.

Process Description. Raw shale from the feed bins is conveyed to the feed hoppers, which lay the feed shale on the grate in beds of controlled thickness. The shale is heated and cooled by passing gases downward through the shale bed. The raw shale is heated by flue gases from the recycle gas combustor and by combustion of coke on the retorted shale. The combusted shale is cooled by recycle gas flows and combustion air flows. All process gases are contained and distributed by hoods over the bed and windboxes below the grate. Water seals above and below the grate control gas leakage from the retort.

Retorting temperatures are precisely controlled to minimize heat consumption by decomposition of mineral carbonates. Combustion zone temperatures are

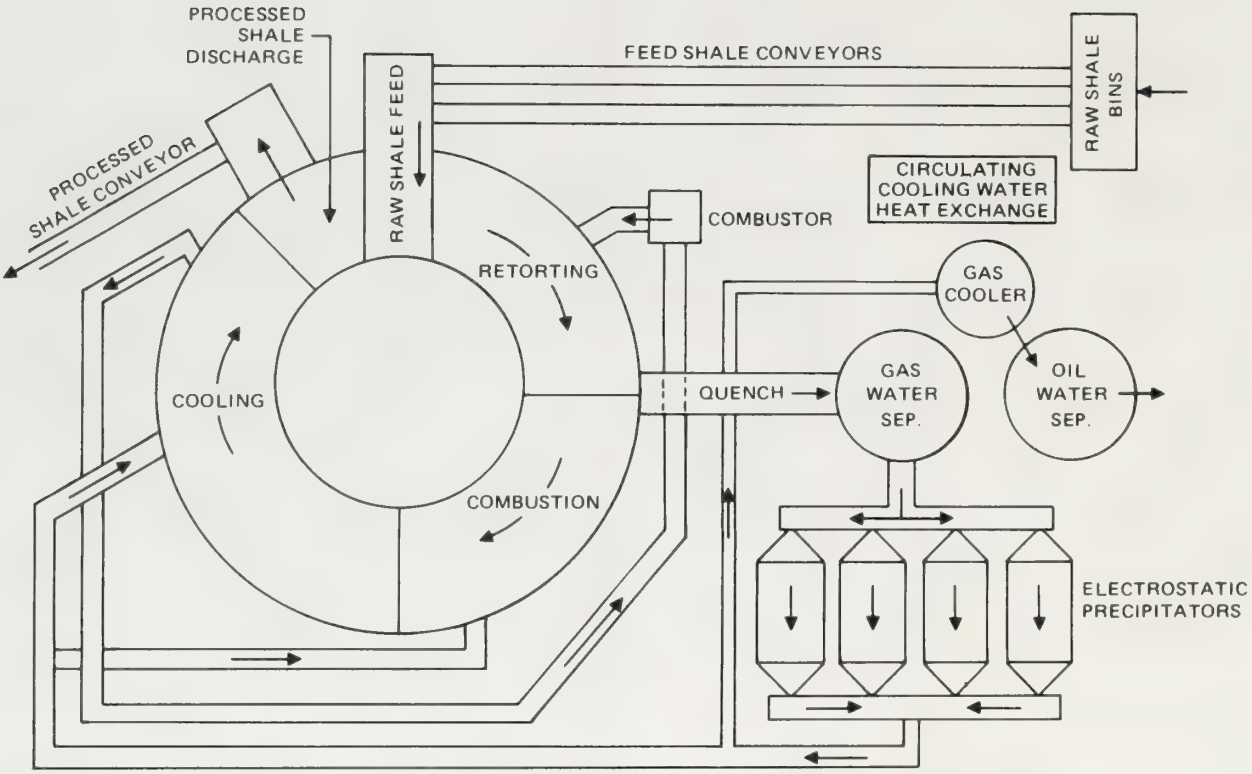


Figure 4-8 GENERAL LAYOUT, CIRCULAR-GRATE DH SUPERIOR RETORT

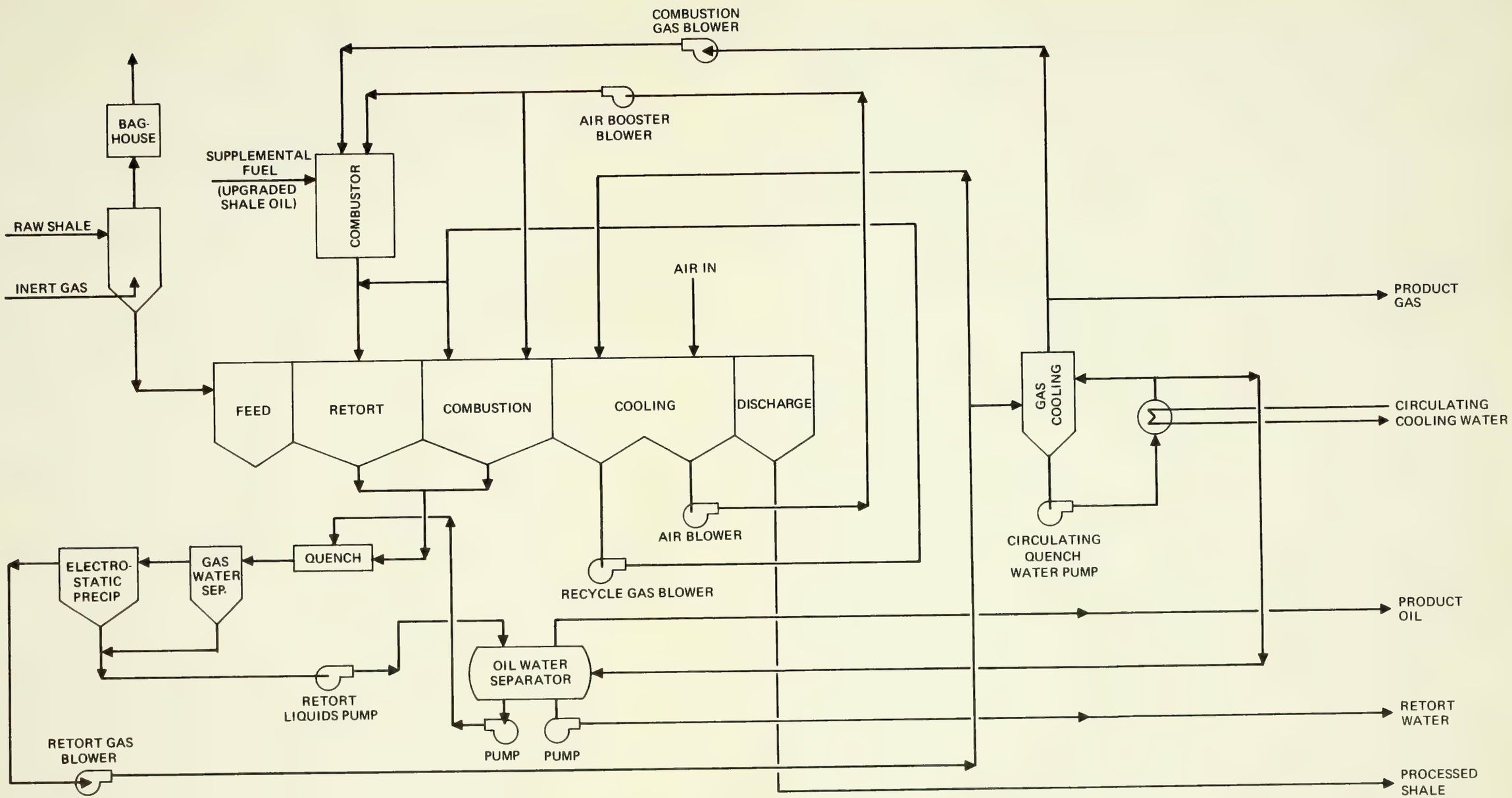


Figure 4-9 FLOW SCHEMATIC, CIRCULAR-GRATE DH SUPERIOR RETORT

controlled by supplying air to the combustion zone. The raw shale feed hoppers are purged with inert gas to eliminate oxygen input to the retort zone.

The retort gases, which contain product oil both as a vapor and a mist, are quenched and coalesced. The product liquids, which are a mixture of oil and water, are recovered in an electrostatic precipitator. Retort water is separated from the oil and recirculated to the quench system. Product oil is pumped to a desalter for solids removal.

The low-Btu retort gas is split; part is recycled to process for recovery of heat from the shale and the remainder, which is the product gas, is compressed for use as fuel. Part of the product gas is used as fuel in the combustor. The remainder is incinerated to allow steam production in a heat recovery boiler. Supplemental fuel in the form of upgraded shale oil will be required for all low-Btu gas combustion.

The processed shale is dumped off the grate into a water seal tank. A screw conveyor removes the processed shale to a processed shale collection conveyor.

The inert gas used to purge the feed shale hoppers releases its shale dust load in a baghouse before discharge to the atmosphere. The water seal at the processed shale discharge conveyor suppresses all dust formed during the discharge operation. The retort product gas passes through an electrostatic precipitator before it is incinerated.

The water quench of the retort gases scrubs the gas of much of its sulfur content. This sulfur is removed in the retort product water as sulfates.

Product Characteristics. The estimated composition of the raw shale oil and low-Btu gas produced by the Superior retort is summarized in Tables 4-2 and 4-3.

Table 4-2

COMPOSITION OF RAW SHALE OIL:
SUPERIOR RETORT

Parameter	Value
Gravity, °API	24.0
Sulfur, wt %	0.8
Nitrogen, wt %	2.3
Distillation (ASTM D-1160)	
IBP, F	359
50, F	720
80, F	888

Table 4-3

COMPOSITION OF LOW-BTU GAS:
SUPERIOR RETORT

Component	Wt % Dry Basis (ppmv)
H_2	3.21
N_2	76.83
CO	0.35
CO_2	16.18
Total Sulfur	(175)
NH_3	(10)
C_1	1.61
C_2's	0.65
C_3's	0.44
C_4's	0.28
C_5+	0.45
Total	100.00
HHV	75 Btu/scf

4.3.3 Vertical-Shaft Indirect-Heated Union B Retort

The vertical-shaft indirect-heated (IH) Union B retort has four significant features that distinguish it from the other retorting technologies:

- Moving Bed. The shale is processed as a moving bed that progresses upward through the circular retort vessel. The driving force is a mechanical rock pump that forces raw shale up into the bottom of the retort via a piston in cylinder action.

- Counter-current Gas Flow. Gas flow is downward, counter-current to the shale flow.

- Heated by Recycle Gas. The only heat input to the retort is by recycle gas that is heated in a furnace external to the retort. The recycle gases are heated indirectly, and are not diluted with the combustion gases.

- No Heat Recovery from Processed Shale. The processed shale is discharged at retorting temperatures and is quenched in water seal pots.

A schematic flow diagram of the Union B retorting process is shown in Figure 4-10.

Mechanical Description. The principal features of the Union B retort are shown schematically in Figure 4-11. The significant items of equipment are the retort, rock pump, feed chutes, retort gas scrubber, recycle gas compressor, and recycle gas heater.

Process Description. Raw shale is introduced into the dual feed chutes, which are sealed with light oil. From these chutes, the raw shale is delivered into the retort chamber by a rock pump piston. In the retort chamber, the shale contacts hot recycle gas, which is introduced at the top of the chamber. The products of kerogen pyrolysis descend to the bottom of the retort where they are withdrawn at two levels as oil and high-Btu gas. Processed shale is ejected to chutes at the top of the retort chamber, quenched in the water seal, and conveyed to disposal.

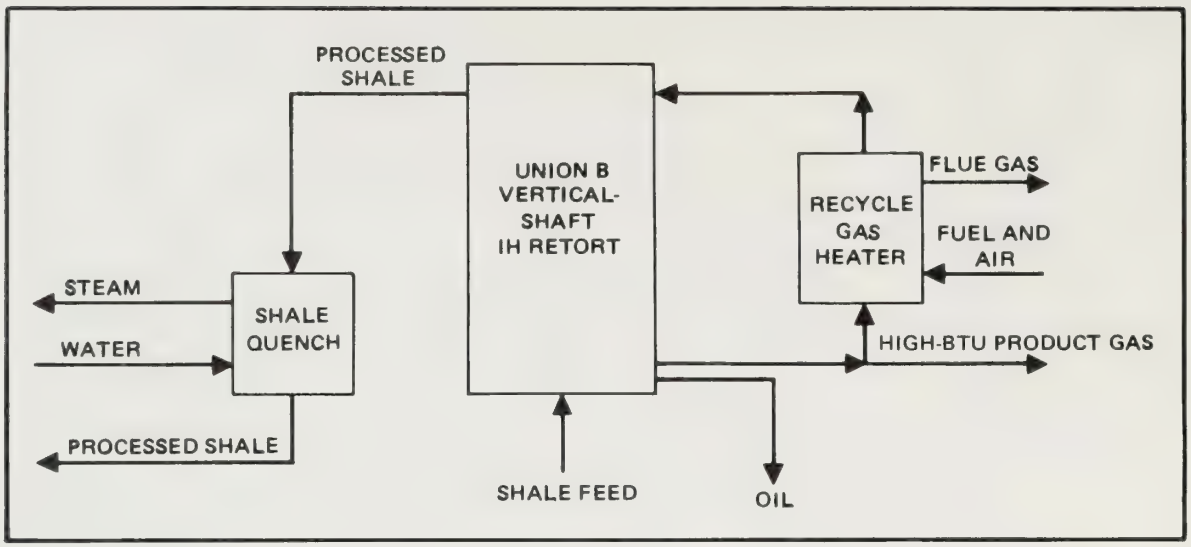


Figure 4-10 SCHEMATIC FLOW DIAGRAM OF VERTICAL-SHAFT IH UNION B RETORT

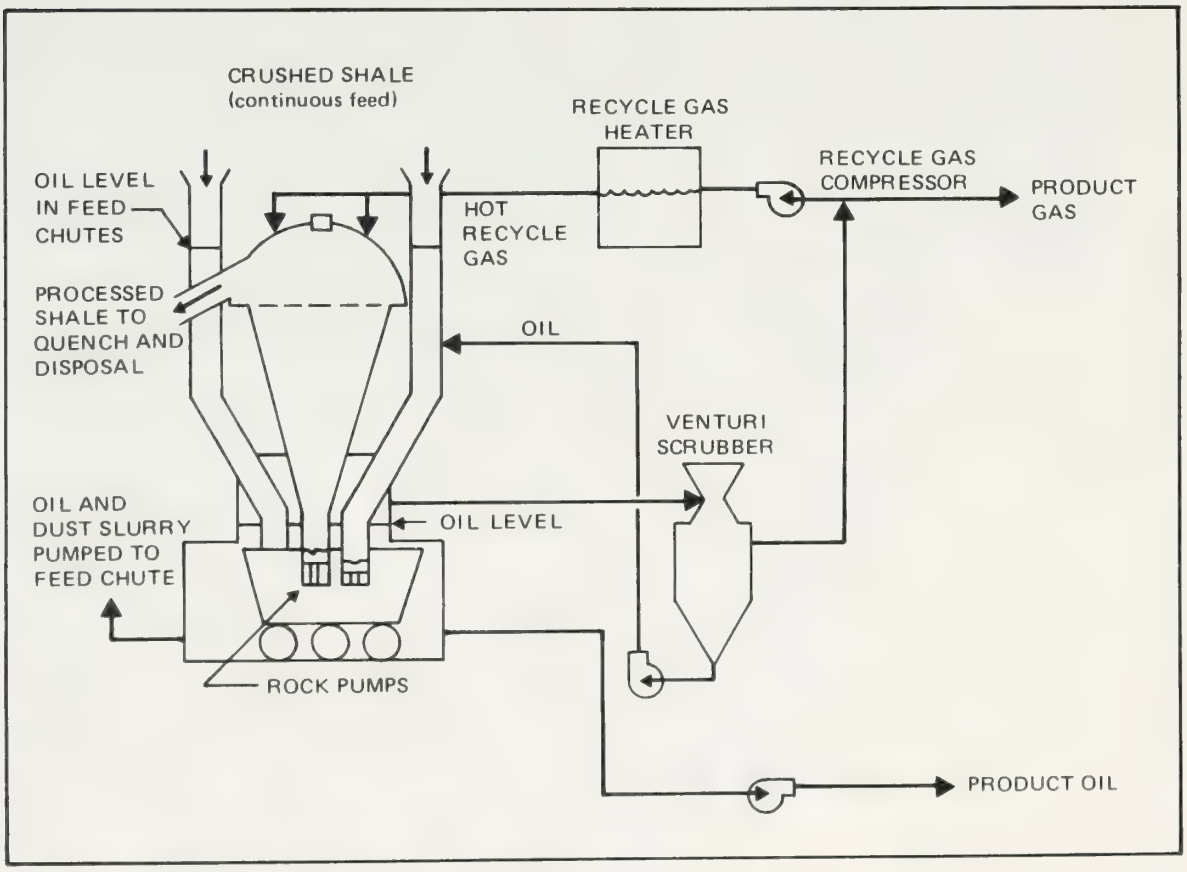


Figure 4-11 PRINCIPAL FEATURES OF VERTICAL-SHAFT UNION B RETORT

Produced gas is cooled to condense light oils. The gas is then split into recycle gas and net product gas. The recycle gas is heated in a fired heater and fed to the top of the retort. The product gas is scrubbed, treated to remove ammonia and certain sulfur compounds, and compressed before being used as fuel.

Product Characteristics. The estimated composition of the raw shale oil and high-Btu gas produced by the vertical-type IH retort is summarized in Tables 4-4 and 4-5.

Table 4-4

COMPOSITION OF RAW SHALE OIL:
UNION B RETORT

Parameter	Value
Gravity, ^{o}API	20.2
Sulfur, wt %	0.55
Nitrogen, wt %	1.93
Distillation (ASTM D-1160)	
IBP, F	152
50, F	799
EP, F	1,100

Table 4-5

COMPOSITION OF HIGH-BTU GAS:
UNION B RETORT

Component	Vol % Dry Basis (ppmv)
H_2	29.27
N_2	—
CO	6.64
CO_2	16.86
H_2S	3.23
Other Sulfur Compounds	(1150)
NH_3	(1200)
C_1	21.37
C_2's	9.76
C_3's	6.62
C_4's	3.69
C_5^+	2.56
Total	100.00
HHV	806 Btu/scf

4.3.4 Fines-Type TOSCO II Retort

The fines-type TOSCO II retorting process uses a solid heat carrier to achieve an indirect heating mode. The shale is heated by direct contact of the raw shale with the solid heat carrier in a rotating kiln.

The fines-type retorting process has four significant features that distinguish it from other retorting technologies:

- Fluid Bed/Rotating Kiln. Solids transport is a mixture of fluidized bed and rotating kiln technologies. In all steps, the shale is processed as a moving bed.

- Solid Heat Carrier. The major heat input is by direct contact with ceramic balls that have been heated by combustion of retort gas.

- Indirect Heat. Combustion flue gases do not mix with the retorting products, so a high-Btu gas is produced.

- Particle Size. The raw shale feed must be less than ¼ inch in size, and the processed shale is produced as a micron size powder.

Mechanical Description. The TOSCO II retort system is shown in Figure 4-12. This simplified schematic indicates the major functional items of equipment.

Process Description. Raw oil shale is first contacted with ball heater flue gas to preheat the solids before delivery into the pyrolysis drum. The preheat step takes place in a series of lift pipes, which also elevates the shale to retort height.

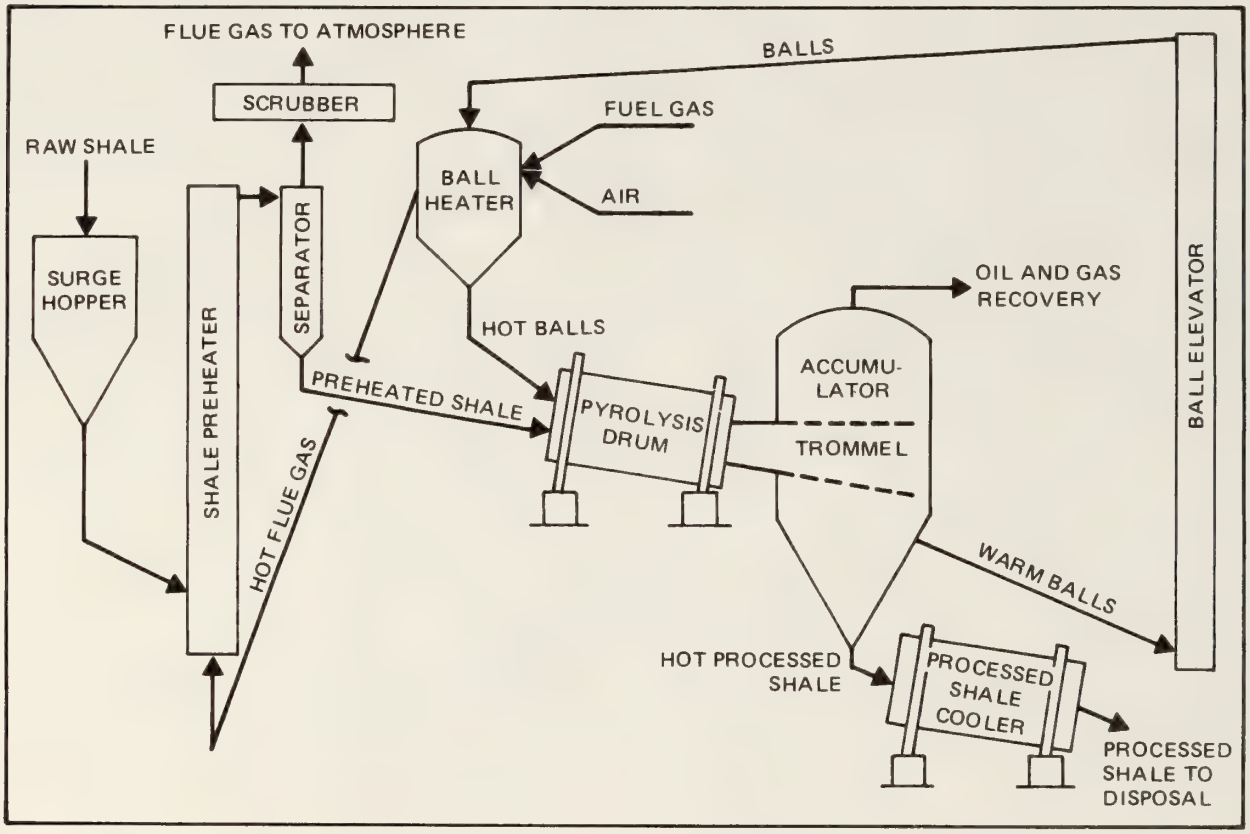


Figure 4-12 FINES-TYPE TOSCO II RETORT

Pyrolysis of the kerogen in the raw shale is accomplished in the pyrolysis drum by contacting the preheated shale with heated ceramic balls. In the pyrolysis drum, the crushed shale and ceramic balls are mixed to effect rapid heat transfer. The pyrolysis drum discharges directly into the accumulator.

Processed shale and balls from the drum are separated in a cylindrical trommel located within the accumulator. The warm balls pass from the accumulator to a ball elevator, while the processed shale discharges from the bottom of the accumulator to the processed shale cooler. Vaporized product shale oil and gas exit from the top of the accumulator.

Processed shale cooling is accomplished in two stages. In the first stage, the hot processed shale from the trommel is cooled in a rotating steam generator. In the second stage, the processed shale is cooled further by direct water quench in another rotating vessel. The cooled, moisturized shale is then delivered to processed shale disposal.

The ball elevator returns the balls to the ball heater, where they are heated to the required temperature by the combustion of fuel gas. The hot flue gases, after heating the balls, pass to the shale preheater. Raw shale oil is condensed from the vapors leaving the retort section. The remaining gas is compressed and treated to remove ammonia and sulfur compounds before being used as fuel.

Product Characteristics. The estimated composition of the raw shale oil and high-Btu gas products of the fines-type TOSCO II retort are summarized in Tables 4-6 and 4-7.

Table 4-6

COMPOSITION OF RAW SHALE OIL:
TOSCO II RETORT

Parameter	Value
Gravity, °API	22
Sulfur, wt %	0.7
Nitrogen, wt %	1.9
Distillation (ASTM D-1160)	
IBP, F	100
50, F	705
EP, F	1,100

Table 4-7

COMPOSITION OF HIGH-BTU GAS:
TOSCO II RETORT

Component	Vol % Dry Basis (ppmv)
H_2	19.00
N_2	—
CO	3.21
CO_2	20.18
H_2S	3.84
NH_3	1.02
C_1	19.00
C_2's	15.01
C_3's	9.77
C_4's	4.89
C_5+	4.08
Total	100.00
HHV	980 Btu/scf

4.4 GAS AND OIL PROCESSING

The gas and oil products from the retorts will undergo treatment before being used as fuel, or transported from the site as a final product. This treatment is discussed below.

4.4.1 Raw Shale Oil Treatment

Raw shale oil will be processed for removal of water and solids by conventional desalting technology and for nitrogen and sulfur removal by high-pressure hydroprocessing.

Desalting. Raw shale oil from the Union B and TOSCO II retorts will undergo conventional two-stage desalting. Dehydration occurs in the first stage and solids removal occurs in the second stage. Chemical demulsifiers and electrical current will be used to speed the separation processes.

Raw shale oil from the Superior retort will be given only second-stage desalting for solids removal. Figure 4-13 is a schematic of the desalter system.

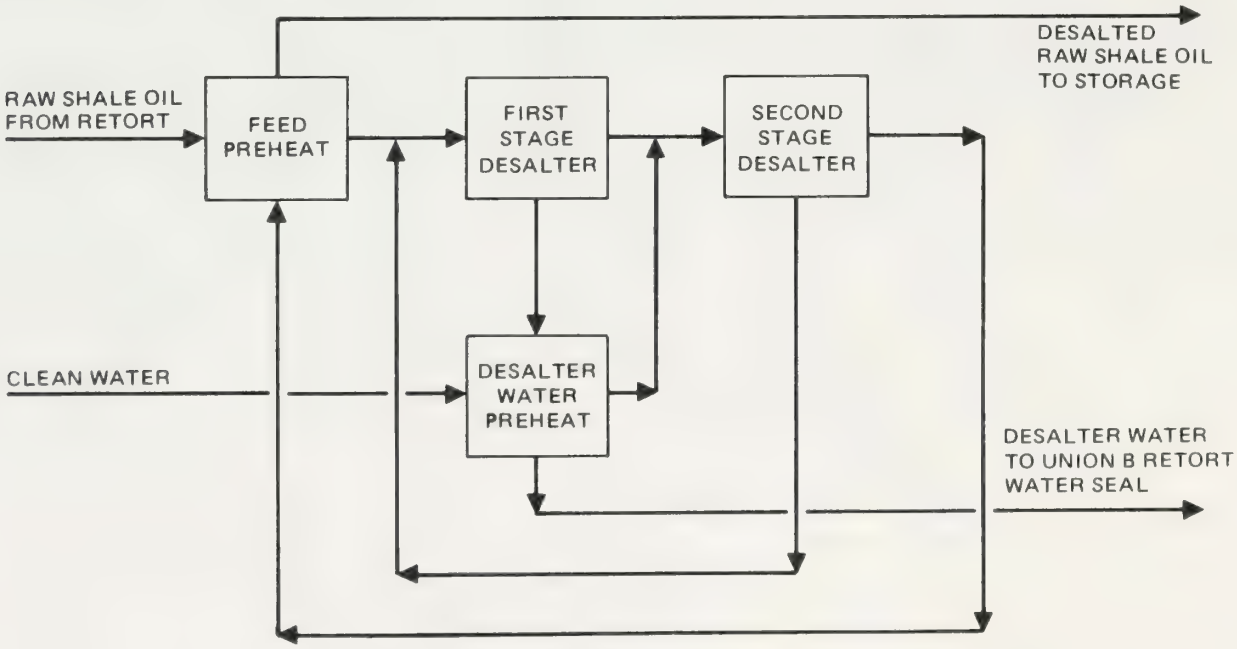


Figure 4-13 DESALTER SYSTEM

Hydroprocessing. A schematic flow diagram for the upgrading process is shown in Figure 4-14. Raw shale oil will be pretreated in guard bed reactors at high hydrogen pressure to remove arsenic, iron, and other metals that deactivate hydroprocessing catalysts. These catalyst poisons will physically adsorb on inert alumina catalyst support material, which will be removed from the guard bed reactors on a monthly basis and landfilled in a controlled hazardous waste disposal site.

The pretreated raw shale oil will be processed for catalytic removal of nitrogen and sulfur under high hydrogen pressure and severe catalyst exposure. This processing will result in a 106.7 percent oil volume yield and production of assorted hydrocarbon gases mixed with large quantities of ammonia and hydrogen sulfide produced by the reaction of hydrogen with nitrogen and sulfur. The hydroprocessing gases will be separated from the liquid products by two-stage (high pressure and low pressure) flash and then water-washed for virtually complete removal of ammonia and hydrogen sulfide. The cleaned product gases will be recycled to the hydrogen plant (see Sec. 4.4.3) for conversion to 97 percent hydrogen gas used as feed to the hydroprocessing units. Most of the high-Btu gas produced by the Union B and the TOSCO II retorts is also consumed as hydrogen plant feedstock. The wash water liquid is sent to the WWT plant for ammonia and hydrogen sulfide recovery. A schematic for the ammonia and sulfur recovery system is shown in Figure 4-15.

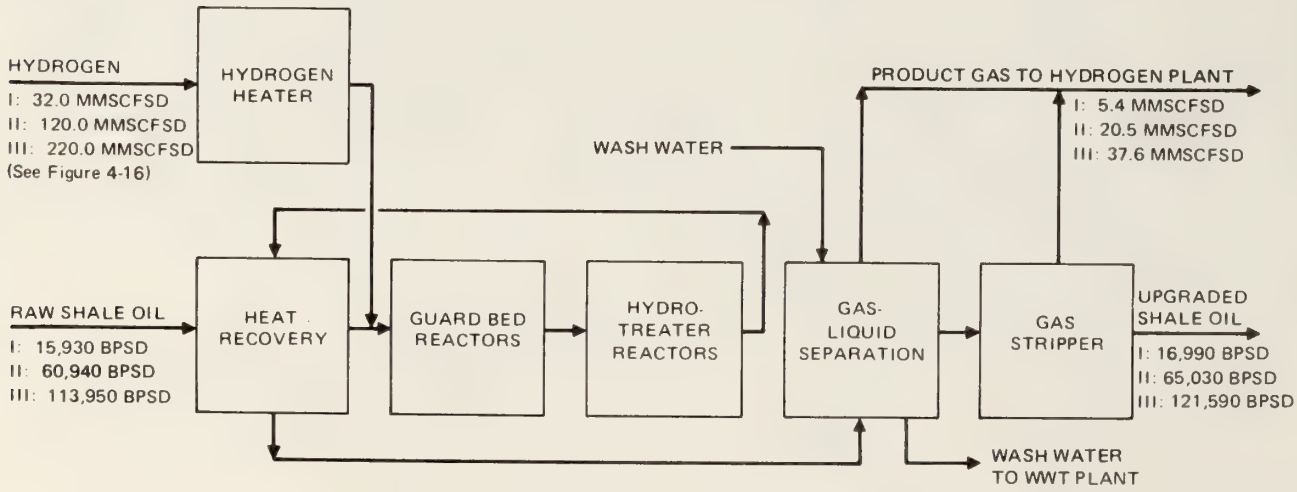


Figure 4-14 PROPOSED UPGRADING SYSTEM

Sour Water Processing. The hydrotreater wash water containing up to 3.5 weight percent ammonia and 0.9 weight percent H_2S will be mixed with sour water from the Union B and TOSCO II retorts and sent to a WWT (sour water treatment) plant for ammonia and hydrogen sulfide recovery. The combined sour water streams will be equalized in a large storage tank, then degassed. Vapors from the degassing step contain hydrocarbons, gaseous ammonia, and hydrogen sulfide in minute amounts, which are sent to the flare. The degassed sour water is then sent to the hydrogen sulfide stripper where the hydrogen sulfide is produced as a gas at 95 percent purity and sent to the Claus plant for sulfur recovery.

After hydrogen sulfide recovery, the water is sent to an ammonia stripping column where the ammonia is produced as a gas containing trace quantities of hydrogen sulfide. The water, now essentially free of hydrogen sulfide and ammonia, is sent to the WWT plant for processing.

The ammonia stream is purified in a two-stage washing process using cold anhydrous ammonia as the wash stream in the first stage and caustic as the wash stream in the second stage. The second-stage product is compressed and cooled to produce anhydrous liquid ammonia.

4.4.2 High-Btu Gas Treatment

The high-Btu gas from the Union B and the TOSCO II retorts will contain ammonia and sulfur at concentrations too high to allow use of the gas as fuel. These gases will be processed for ammonia and sulfur removal.

Ammonia Removal. The high-Btu gas will be passed through water-wash towers where essentially all the ammonia and trace quantities of hydrogen sulfide will be removed. This water will be sent to the ammonia-hydrogen sulfide plant with the hydroprocessing water.

Hydrogen Sulfide Removal. Following water-wash, the high-Btu gas will be processed in an amine absorption tower where essentially all of the hydrogen sulfide and part of the carbon dioxide will be removed. The amine will be

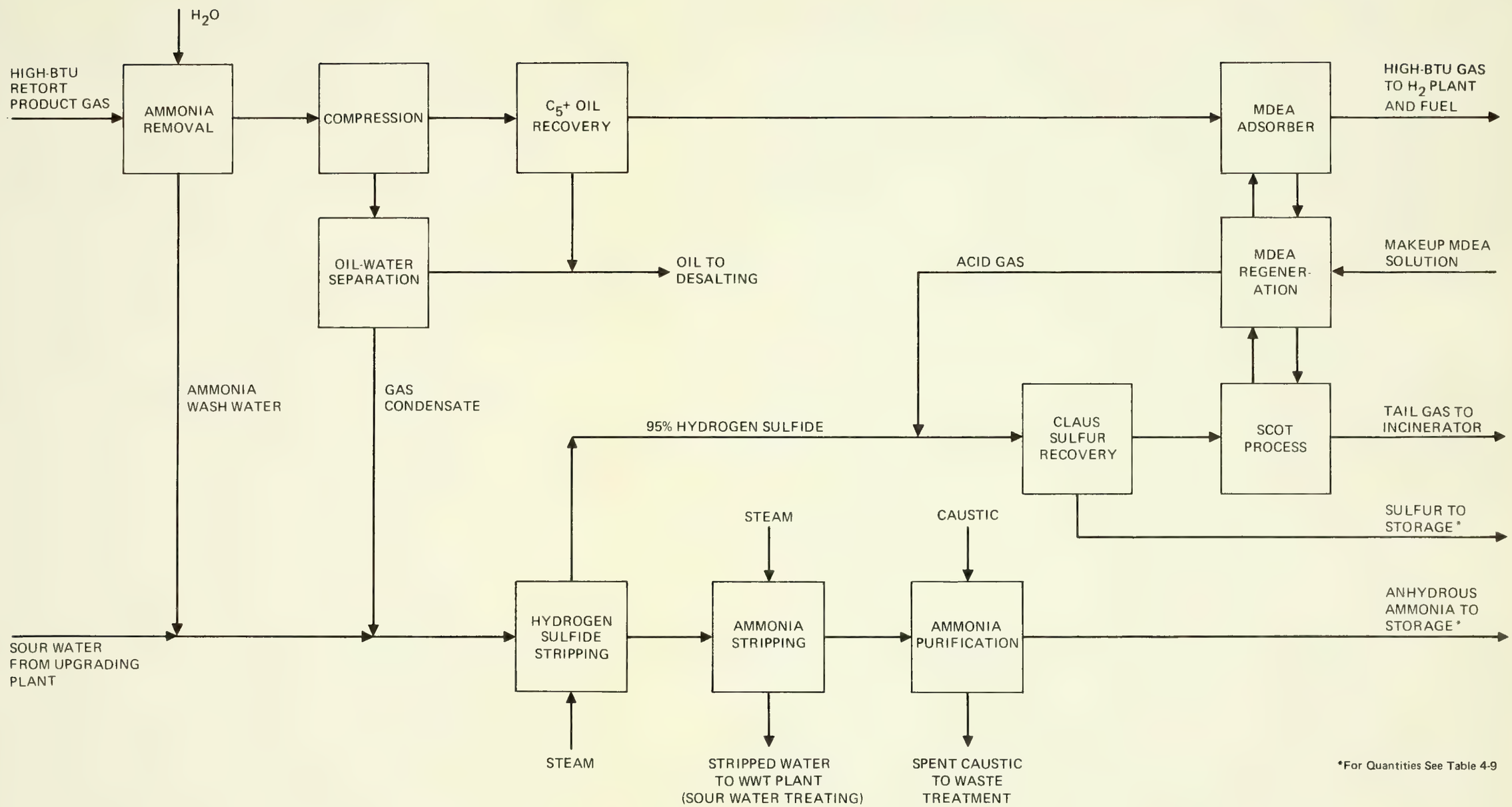


Figure 4-15 SULFUR AND AMMONIA RECOVERY SYSTEM

regenerated to produce an acid gas mixture of hydrogen sulfide and carbon dioxide, which will be sent to the Claus plant for sulfur recovery.

Sulfur Recovery. The acid gases from the MDEA (Methyl Diethanolamine) regenerators, the SCOT process, and the hydrogen sulfide stream from the sour water treatment plant will be processed in a three-stage Claus plant for sulfur recovery. Table 4-9 presents the quantity recovered for each phase. A total of six Claus units will be operational during Phase III. Excess Claus plant capacity is provided so that, in any phase, with any one Claus plant out of service, adequate capacity is available for the entire sulfur recovery load.

The gas streams are combined, they pass through a knockout drum for removal of liquids, and then they flow to the thermal reactor. In the thermal reactor, approximately 50 percent of the hydrogen sulfide is converted to sulfur by reaction with oxygen, and 17 percent of the hydrogen sulfide is converted to sulfur dioxide. The effluent from the thermal reactor is cooled by production of high-pressure steam, then further cooled by production of low-pressure steam to condense molten sulfur.

The tail gas is then processed in three catalytic reaction stages to react the hydrogen sulfide and sulfur dioxide together to form sulfur and water. Before each stage, the gases are heated to reaction temperature; after each stage, the gases are cooled by generation of low-pressure steam to condense molten sulfur.

Molten sulfur flows from all four condensers to a heated pit, and is then pumped to a casting station where it is solidified for storage.

Cost effectiveness limits sulfur recovery in the Claus plant to 95 percent. This requires a tail gas treating unit to reduce sulfur to discharge levels.

Tail Gas Treating. The Shell Claus off-gas treating (SCOT) process will be used to process Claus plant tail gas. The unit will be sized for 94 percent recovery in the Claus plant.

Claus plant tail gas will be heated by in-line combustion of high-Btu gas, and then processed in a catalytic hydroprocessing reactor to convert all sulfur forms to H_2S. The gas is then cooled by generation of low-pressure steam, quenched, and processed in an MDEA adsorber for high efficiency removal of hydrogen sulfide.

Following adsorption, the tail gas will contain approximately 250 ppm sulfur as SO_2. The tail gas will be incinerated to convert all H_2S to SO_2, then discharged to the atmosphere.

The MDEA will be regenerated in a reboiled stripper, and the acid gas produced will be recycled to Claus plant feed.

4.4.3 High-Btu Gas Utilization

The high-Btu gas will be used as hydrogen plant feedstock and process heater fuel.

Hydrogen Plant. Hydrogen will be manufactured from hydrotreater recycle gas and high-Btu retort gas using the steam-methane reforming process. The hydrogen plant operations are shown on Figure 4-16.

Hydrotreater gas will be supplemented with high-Btu gas as necessary to meet the hydrogen plant feedstock requirements. The feed gas will be hydrotreated over a Co/Mo (Cobalt/Molybdenum) catalyst to convert the bulk of the sulfur compounds to hydrogen sulfide, which will then be removed in an MDEA absorption tower. The feed gas will then receive a second stage of hydrotreatment over Co/Mo catalyst to convert all residual sulfur to hydrogen sulfide, which will then be removed by adsorption on zinc oxide beds. Catalyst replacement will be on the order of one year, at which time the zinc oxide beds will be disposed of as land fill.

The feed gas will then be reacted with steam over the catalyst to produce hydrogen and carbon monoxide. The reaction takes place in the tubes of a reforming furnace which uses upgraded shale oil as fuel. Catalyst replacement

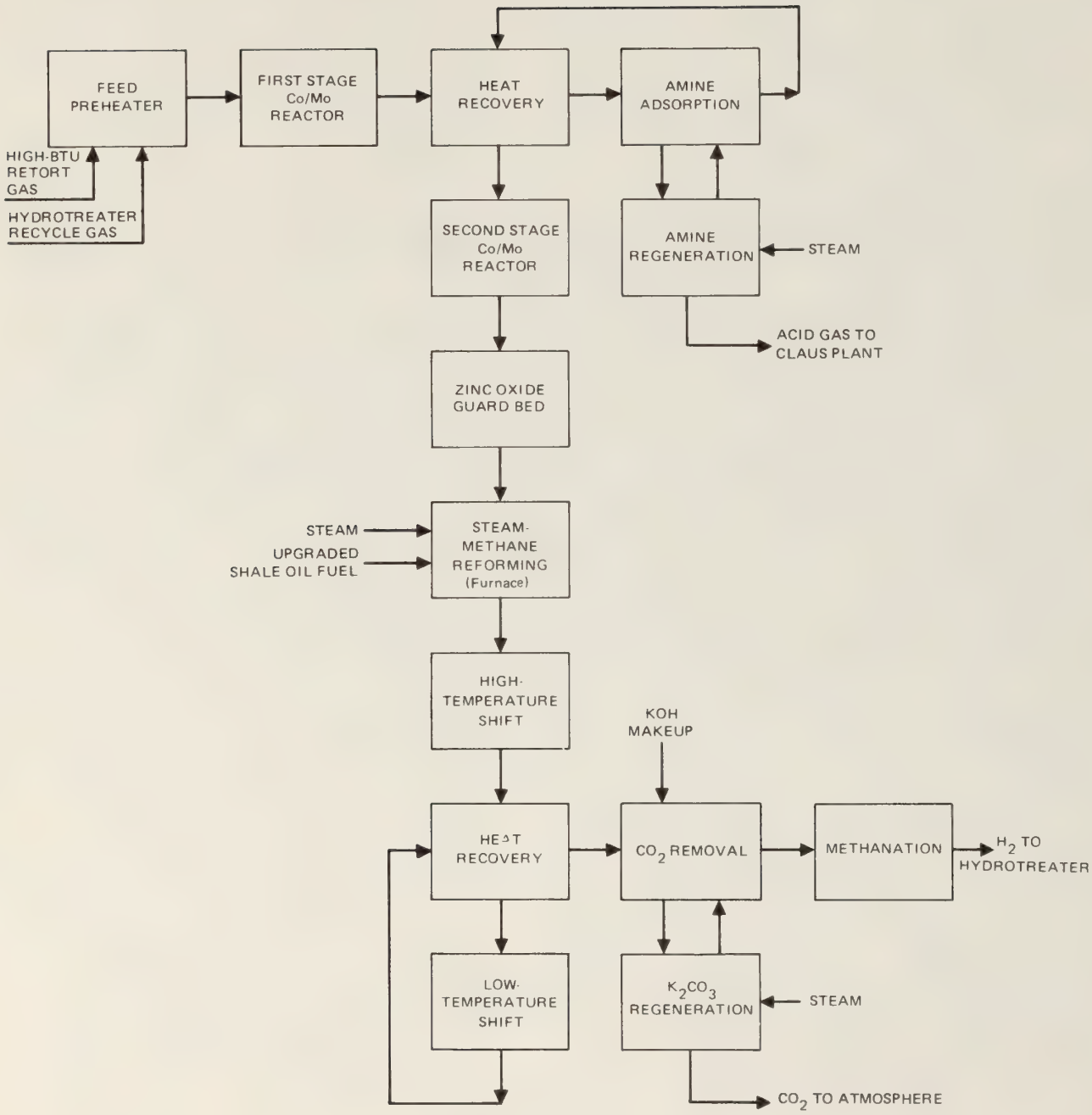


Figure 4-16 SCHEMATIC DIAGRAM OF HYDROGEN PLANT

will be ten years or more. Reformer furnace effluent is cooled via generation of high-pressure steam and preheating of feed steam; it is then processed in a high-temperature shift reactor for partial conversion of carbon monoxide to carbon dioxide by reaction with steam to release additional hydrogen. Following cooling by generation of low-pressure steam, the shift reaction is completed in a low-temperature stage to provide a gas stream composed principally of hydrogen and carbon dioxide with traces of carbon monoxide and unreacted hydrocarbon gases.

The shift effluent gas is cooled and processed in an absorber tower where potassium hydroxide solution is used to remove CO_2 from the gas, producing a 97 percent hydrogen gas product. The hydrogen stream is processed in a methanator to convert trace amounts of carbon monoxide and dioxide to methane. The hydrogen is then ready for use in the upgrading plant.

The potassium carbonate solution from the carbon dioxide absorber is regenerated to potassium hydroxide in a reboiled stripping tower. The released carbon dioxide is vented to the atmosphere.

Process Heater Fuel. All high-Btu gas not needed for hydrogen plant feedstock will be used as fuel. The fraction of high-Btu gas used as fuel varies significantly between phases, as shown in Table 4-8.

Table 4-8

HIGH-BTU GAS UTILIZATION
(MMSCFSD)

Use	Phase I	Phase II	Phase III
Hydrogen Plant Feed	5.4	19.5	34.4
Fuel	2.5	18.0	8.9
Total	7.9	37.5	43.3

4.4.4 Low-Btu Gas Utilization

The low-Btu gas from the Superior retort will be water-washed within the retort to remove sulfur and ammonia, and will then be incinerated. Supplemental fuel will be required for the incineration process, and upgraded shale oil will be used as the supplemental fuel. Heat recovery boilers will be installed to produce high-pressure steam from the incinerator flue gas heat. The steam will be used for process heat in all phases, and electricity will be generated from excess steam in Phases II and III and consumed on site.

4.4.5 Product and By-Product Production Rates

Expected production rates of products and by-products are listed in Table 4-9. These include oil, sulfur, ammonia, and electric power.

Table 4-9

OIL, SULFUR, AMMONIA, AND ELECTRIC POWER PRODUCTION

Product/By-Product	Phase I	Phase II	Phase III
Raw Shale Oil, BPSD	15,930	60,945	113,950
Upgraded Shale Oil, BPSD	16,990	65,030	121,590
Consumption as Fuel, BPSD	2,150	7,830	15,360
Net Syncrude Product, BPSD	14,840	57,200	106,230
Anhydrous Ammonia, TPSD	65.4	245.4	449.4
Sulfur, STPSD	29.4	125.2	204.0
Electric Power,[a] MW	0	18	93

(a) For internal consumption

4.5 PROJECT NET ENERGY BALANCE

Table 4-10 presents the total energy balance of the project by phase.

Table 4-10

PROJECT NET ENERGY BALANCE

Energy	Phase I		Phase II		Phase III	
	Quantity	MMBtu/day	Quantity	MMBtu/day	Quantity	MMBtu/day
A. Energy Out:						
Net Syncrude Product	14,840 BPSD	86,100	57,200 BPSD	331,800	106,230 BPSD	616,100
B. Energy In:						
Electrical Power[a]	35 MW	9,600	112 MW	30,600	150 MW	41,000
Diesel — Mine and Utilities	80 BPSD	500	370 BPSD	2,200	665 BPSD	3,900
Fuel Oil — Mine and Utilities	62 BPSD	400	155 BPSD	1,000	443 BPSD	2,700
Propane — Processing Plant	23 BPSD	100	62 BPSD	250	62 BPSD	250
Naphtha — Processing Plant	192 BPSD	1,100	0	0	0	0
Net Energy Produced by Project (A - B)		74,400		297,750		568,250

[a] Assuming over-all power plant efficiency of 30%

REFERENCES - SECTION 4

4-1 WRSP Preliminary Rock Mechanics Report, Cleveland-Cliffs Iron Company, Western Division, Rifle, Colorado, October 2, 1975.

4-2 WRSP Geologic Exploration Program Report, Cleveland-Cliffs Iron Company, June 30, 1975.

4-3 WRSP Geophysical Logging Report, Cleveland-Cliffs Iron Company, July 1, 1975.

4-4 White River Shale Project, Detailed Development Plan (in press), WRSP, Vernal, Utah, 1981.

Section 5

FACILITY EMISSIONS

This section describes all air pollutant emissions and source characteristics associated with the White River Shale Project. In accordance with PSD regulations, the section also discusses good engineering practice (GEP) stack height, *de minimis* emission levels, and best available control technology (BACT).

5.1 CRITERIA POLLUTANT EMISSION ESTIMATES

The criteria pollutants (i.e., pollutants for which ambient air quality standards have been established) include sulfur dioxide, nitrogen dioxide, ozone, nonmethane hydrocarbons, carbon monoxide, total suspended particulate, and lead.

5.1.1 Construction Emissions

Phase I. A total of 236 acres will be disturbed during site development activity. Of these, 44 acres will be disturbed by construction of the paved access road from Highway 45 to the site, and 11 acres will be disturbed by construction of the utility corridor. The remaining 181 acres constitute the area for the retorts, upgrading, storage, and auxiliary facilities at the site.

Once construction begins, activity will increase to a peak level where up to 181 acres on site will be disturbed. The construction area will then decrease to about 10 acres attributable to Phase I operations.

EPA Report AP-42 (Ref. 5-1) suggests that an uncontrolled emission factor of 1.2 tons of total suspended particulates (TSP) per acre per month can be used to estimate particulate emissions from construction activities. Watering, chemical dust suppressants, and other construction dust control measures are expected to provide a control efficiency of 50 percent. The daily controlled TSP emission factor is then 57 lb/acre-day, based on 21 working days/month.

Site development will be performed gradually and steadily over a 1-year period. At any one time, 20 acres will be involved in site development. The emission rate during the first year of Phase I is then:

$$(57 \text{ lb/acre-day})\ (20 \text{ acres}) = 1{,}140 \text{ lb TSP/day}$$

Construction is scheduled to begin near the halfway point of site development. By this time, the access road and utility corridor to the site will have been completed (55 acres); thus, the daily emission rate during peak construction activity, including concrete batching, will amount to:

$$(57 \text{ lb/acre-day})\ (181 \text{ acres}) = 10{,}317 \text{ lb TSP/day}$$

After Phase I construction of retorting and upgrading facilities is complete, Phase I operations will continue to result in 570 lb/day of construction related emissions until Phase II begins, based on approximately 10 acres of disturbed area on the surface.

Phase II. A total of 178 acres will be disturbed during site development activity. Of this total, approximately 31 acres will extend off site as a utility corridor and 147 acres will be required for onsite retorts, upgrading, storage, and auxiliary facilities.

Site development will be performed gradually and steadily over a 6-month period. At any one time, 25 acres will be under development. The emission rate during this time will be:

(57 lb/acre-day) (25 acres) = 1,425 lb TSP/day

By the time construction peaks, the utility corridor will have been completed; thus, the maximum daily emission rate, including concrete batching, will be:

(57 lb/acre-day) (147 acres) = 8,379 lb TSP/day

Phase III. A total of 164 acres will be developed in Phase III in 20-acre sections during each month. This will occur over approximately 8 months. During this time, emissions will amount to:

(57 lb/acre-day) (20 acres) = 1,140 lb TSP/day

The emission rate during peak construction activity and concrete batching will be:

(57 lb/acre-day) (164 acres) = 9,348 lb TSP/day

A schedule showing construction emissions for the entire project is presented in Section 5.1.3.

5.1.2 Operational Phase Emissions

Except for lead, Phase I emission estimates for each of the criteria pollutants are shown in Table 5-1. Total Phase I lead emissions are not expected to exceed 0.06 ton per year (TPY). Figure 5-1 presents the Phase I facility layout with source emission points indicated.

Phase II emissions are given in Table 5-2 and Phase III emissions are shown in Table 5-3. Phase II emissions will amount to about one-half of those of Phase III. Although lead emissions are not shown in the tables, very small amounts of lead may be emitted as a result of trace concentrations of lead in the dust generated by the facility and in the combustion flue gases. Phase III lead emissions are not expected to exceed 0.5 TPY. Figure 5-2 presents the emission points for full Phase III operations. All emission calculations for the criteria pollutants are provided in Appendix A.

5.1.3 Emissions Schedule

Figure 5-3 is a schedule of daily particulate emissions from construction activities and all production operations for each year of the project. Figure 5-4 displays the daily SO_2, NO_x, CO, and HC emissions.

5.2 NON-CRITERIA POLLUTANT EMISSION ESTIMATES

Pollutants whose emissions are regulated by the Clean Air Act but which are not controlled by ambient air quality standards have been termed "non-criteria" pollutants by the EPA. Non-criteria pollutants include fluorides, asbestos, beryllium, mercury, vinyl chloride, sulfuric acid mist, hydrogen sulfide, total reduced sulfur, and reduced sulfur. Many of these pollutants may occur as trace elements in certain raw materials, by-products, and gaseous and liquid emissions. It is important to note, however, that one of the non-criteria pollutants is peculiar to the oil shale industry.

Many industries emit small quantities of these pollutants. Because non-criteria pollutants have only recently become part of the PSD review process, relatively few data are available to quantify emissions. Based on the available information, emission estimates for each of the non-criteria pollutant categories are described below. Emission calculations are provided in Appendix B. Project non-criteria emissions are compared with established *de minimis* levels in Section 5.3.

5.2.1 Fluorides

Fluorine combines with a number of elements in nature to form a wide variety of fluoride compounds. Analyses of both raw and retorted Utah oil shale exhibit fluoride concentrations of 0.12 and 0.15 weight percent, respectively (Ref. 5-2). This shows that nearly all of the fluorides are accounted for in the retorted shale, based on a 20 percent volatiles content. Concentrations of fluorides in the earth's crust are typically near 0.06 weight percent (Ref. 5-2).

Table 5-1

PHASE I AIR POLLUTANT EMISSION INVENTORY

Emission Source	Operational Quantity	Pollutant	Emission Factor Without Control	Control Measure and Efficiency	Total Emission Rate		Emission Height (ft)	Number of Emission Points	Exhaust Diameter (ft)	Exhaust Temperature (°F)	Exhaust Volume (scfm)
					lb/day	t/yr					
1. Mining	Up to 30,000 TPSD	Particulate	0.018 lb/ton[a]	Wet suppression and baffled settling (80%)[a]	108	17.7	Surface	1	28	Ambient	2,000,000
	Up to 18,000 lb ANFO/day for blasting	CO NO_x	0.022 lb/lb ANFO[a,b] 0.012 lb/lb ANFO[a,b]		396 216	65.0 35.5	(Contained in mine vent exhaust)				
	Up to 5,000 gal/day diesel fuel for mine equipment	Particulate CO HC NO_x SO_2	22 lb/1000 gal[c] 90 lb/1000 gal[c] 28 lb/1000 gal[c] 428 lb/1000 gal[c] 31 lb/1000 gal[c]		110 450 140 2,140 155	18.1 73.9 23.0 351.5 25.5	(Contained in mine vent exhaust)				
2. In-Mine Crushing	Up to 15,000 TPSD to primary crusher	Particulate	0.02 lb/ton[d,e]	Wet suppression and and baffled settling (80%)[a]	60	9.9	(Contained in mine vent exhaust)				
	Up to 28,140 TPSD to secondary crusher and screens	Particulate	6 gr/scf[f]	Baghouse (99.7%)[c] (5,000 scfm)	19	3.0	(Contained in mine vent exhaust)				
3. Mine Conveyor Feed Bin	28,140 TPSD	Particulate	4 gr/scf[f]	Baghouse (99.7%)[c]	12	2.0	Surface	1	1.5	Ambient	5,000
4. Storage Silo Feed	27,330 TPSD	Particulate	4 gr/scf[f]	Baghouse (99.7%)[c]	12	2.0	50	1	1.5	Ambient	5,000
5. Surface Crushing and Screening	27,330 TPSD	Particulate	7 gr/scf[f]	Baghouse (99.7%)[c]	65	10.6	50	1	2.5	Ambient	15,000
6. Fines Conveyor Feed	2,730 TPSD	Particulate	0.04 lb/t[g]	Wet suppression (90%)[g,h]	11	1.8	Surface			Ambient	
7. Fines Conveyor Transfer Points	2,730 TPSD	Particulate	0.04 lb/t[g]	Wet suppression (90%)[g,h]	33	5.4	Surface	3		Ambient	
8. Fines Conveyor Discharge to Stacker	2,730 TPSD	Particulate	0.04 lb/t[g]	Wet suppression (90%)[g,h]	11	1.8	Surface			Ambient	
9. Union Conveyor Feed	11,600 TPSD	Particulate	0.006 lb/t[g]	Wet suppression (90%)[g,h]	7.0	1.1	Surface			Ambient	
10. Union Retort Feed	11,600 TPSD	Particulate	3 gr/scf[f]	Baghouse (99.7%)[c]	2.1	0.3	50	1	0.75	Ambient	1,000
11. Superior Conveyor Feed	13,000 TPSD	Particulate	0.006 lb/t[g]	Wet suppression (90%)[g,h]	7.8	1.3	Surface			Ambient	
12. Superior Retort Feed	13,000 TPSD	Particulate	3 gr/scf[f]	Baghouse (99.7%)[c]	16.9	2.8	50	2	1.5	Ambient	8,200

Emission Source	Operational Quantity	Pollutant	Emission Factor Without Control	Control Measure and Efficiency	Total Emission Rate		Emission Height (ft)	Number of Emission Points	Exhaust Diameter (ft)	Exhaust Temperature (°F)	Exhaust Volume (scfm)
					lb/day	t/yr					
13. Union Retort Discharge to Processed Shale Conveyor	9,875 TPSD	Particulate	0.0001 lb/t[g]	Processed shale moisturized to 20% water	1	0.2	Surface	1		Ambient	
14. Superior Retort Discharge to Processed Shale Conveyor	11,000 TPSD	Particulate	0.0001 lb/t[g]	Processed shale moisturized to 20% water	1	0.2	Surface	1		Ambient	
15. Processed Shale Conveyor Discharge to Bin	20,875 TPSD	Particulate	0.0003 lb/t[g]	Processed shale moisturized to 15% water	6.3	1.0	30	1		Ambient	
16. Raw Shale Stockpile											
a. Load-in	810 TPSD	Particulate	0.009 lb/t[g]	Lowering well (75%)[g]	1.8	0.3	Surface			Ambient	
b. Grooming	810 TPSD	Particulate	0.02 lb/t[g]	Watering (50%)[i,o]	16[p]	1.3	Surface			Ambient	
c. Wind erosion	500,000 ton pile (35% live, 65% dead)	Particulate	0.32 lb/t-yr[g]	Watering of live portion (50%)[i,o] Coating of dead portion (95%)[g]	167[p]	17	Surface			Ambient	
17. Fines Stockpile											
a. Load-in	2,730 TPSD	Particulate	0.04 lb/t[g]	Wet suppression (90%)[g,h]	11	1.8	Surface			Ambient	
b. Grooming and Compaction	8 scraper-hours/day	Particulate	16 lb/scraper-hour[i]	Watering (50%)[i,o]	128[p]	10.5	Surface			Ambient	
c. Wind erosion	5 acres	Particulate	6,428 lb/acre-year[g]	Compaction and chemical dust suppression (85%)[i]	13	2.4	Surface			Ambient	
18. Processed Shale Disposal											
a. Load-in	20,875 TPSD	Particulate	0.0003 lb/t[g]	15% moisturized	6.3	1	Surface			Ambient	
b. Dumping	20,875 TPSD	Particulate	0.0003 lb/t[g]	15% moisturized	6.3	1	Surface			Ambient	
c. Road Dust	522 vehicle miles/day	Particulate	2.2 lb/Veh-mi.[i]	Chemical stabilization (85%)[i]	172	28	Surface			Ambient	
d. Wind Erosion	30 acres	Particulate	8,570 lb/acre-yr[g]	Canyon storage, revegetation, compaction, and chemical dust suppressant (85%)[i]	106	19	Surface			Ambient	
e. Grooming and Compaction	24 scraper-hours/day	Particulate	16 lb/scraper-hour[i]	Watering (50%)[i,o]	384[p]	32	Surface			Ambient	
19. Union B Retort — Recycle Gas Heater	211 MMBtu/hr upgraded shale oil; 29 MMBtu/hr high-Btu gas (35 Bbl/hr, 36,000 scf/hr)	Particulate	3 lb/10^3 gal + 15 lb/MMscf[c]	Upgraded shale oil, treated fuel gas, low-NO_x burners	119	20	200	1	4.25	300	45,100
		SO_2	0.284 lb/10^3 gal[c] + 140 lb/MMscf[n]		131	22					
		CO	5 lb/10^3 gal + 17 lb/MMscf[c]		191	31					
		HC	1 lb/10^3 gal + 3 lb/MMscf[c]		38	6					
		NO_x	31 lb/10^3 gal + 210 lb/MMscf[c]		1,275	209					

Emission Source	Operational Quantity	Pollutant	Emission Factor Without Control	Control Measure and Efficiency	Total Emission Rate		Emission Height (ft)	Number of Emission Points	Exhaust Diameter (ft)	Exhaust Temperature (°F)	Exhaust Volume (scfm)
					lb/day	t/yr					
20. Hydrogen Plant Reformer Furnace	383 MMBtu/hr shale oil; 53 MMBtu/hr high-Btu gas (63 Bbl/hr, 65,800 scf/hr)	Particulate	3 lb/10^3 gal + 15 lb/MMscf[c]	Upgraded shale oil, treated fuel gas, low-NO_x burners	214	35	135	1	5.75	330	85,000
		SO_2	0.284 lb/10^3 gal[c] + 140 lb/MMscf[n]		239	39					
		CO	5 lb/10^3 gal + 17 lb/MMscf[c]		344	56					
		HC	1 lb/10^3 gal + 3 lb/MMscf[c]		68	11					
		NO_x	31 lb/10^3 gal + 210 lb/MMscf[c]		2,298	377					
21. Boiler and Steam Plant	255 MMBtu/hr low-Btu gas; 28 MMBtu/hr upgraded shale oil (3.6 MMscf/hr, 4.6 Bbl/hr)	Particulate	0.03 lb/MMBtu[j]	Cleaned and treated fuel gas. Upgraded shale oil.	204	34	100	1 stack, 3 flues	3.6	350	38,500 each
		SO_2	26.6 lb/MMscf[k] and 0.284 lb/10^3 gal[c]		2,325	382					
		CO	17 lb/MMscf and 5 lb/10^3 gal[c]		1,512	248					
		HC	1 lb/MMscf and 1 lb/10^3 gal[c]		91	15					
		NO_x	0.2 lb/MMBtu[l]		1,358	223					
22. Hydrotreater Reactor Feed Furnace	31 MMBtu/hr High-Btu gas (38,400 scf/hr)	Particulate	15 lb/MMscf[c]	Treated and cleaned gas	14	2.3	100	1	2.25	300	5,700
		SO_2	140 lb/MMscf[n]		129	21					
		CO	17 lb/MMscf[c]		16	2.6					
		HC	3 lb/MMscf[c]		2.8	0.5					
		NO_x	230 lb/MMscf[c]		212	35					
23. Flare Pilot	1 MMBtu/hr High-Btu gas (1,240 scf/hr)	Particulate	15 lb/MMscf[c]	Treated and cleaned gas	0.5	0.07	100	1	4.25	150	185
		SO_2	140 lb/MMscf[n]		4	1					
		CO	17 lb/MMscf[c]		0.5	0.08					
		HC	3 lb/MMscf[c]		0.1	0.02					
		NO_x	230 lb/MMscf[c]		7	1					
24. Gas Treatment Plant	Tail gas; 4 MMBtu/hr high-Btu gas (5,000 scf/hr)	SO_2	10,000-20,000 ppmv	Tail gas unit (<250 ppmv)	118	19	100[q]	1	1.75	300	2,200
		Particulate	15 lb/MMscf[c]		1.6	0.3					
		NO_x	230 lb/MMscf[c]		25	4.1					
		HC	3 lb/MMscf[c]		0.3	0.05					
		CO	17 lb/MMscf[c]		1.8	0.3					
25. Union Crude Shale Oil Storage	115,000 Bbl	HC	API equation[c]	Floating roof tank	111	20		1 tank			
26. Superior Crude Shale Oil Storage	125,000 Bbl	HC	API equation[c]	Floating roof tank	129	23		1 tank			
27. Synthetic Crude Oil Storage	120,000 Bbl	HC	API equation[c]	Floating roof tank	111	20		1 tank			
28. Recovered Oil Tank	5,000 Bbl	HC	API equation[c]	Floating roof tank	12	2.2		1 tank			
29. Diesel Fuel Tank	17,500 Bbl	HC	API equation[c]	Fixed roof tank	3.2	0.6		1 tank			
30. Fuel Oil Tank	13,000 Bbl	HC	API equation[c]	Fixed roof tank	0.1	0.02		1 tank			
31. Naphtha Tank	60,000 Bbl	HC	API equation[c]	Floating roof tank	20	3.5		1 tank			
32. Valves, Flanges, Pump Seals, etc.	15.925 Bbl/day	HC	50 lb/10^3 Bbl production[c]	Good housekeeping and maintenance (50%)[m]	398	65					

Notes:

(a) P. W. Marshall, "Mine Dust and Fumes Control," Colony Development Operation, 1974. (See also EPA review of Colony PSD application.)

(b) R. F. Chaiken, E. B. Cook, and T. C. Ruhe, *Toxic Fumes from Explosives Ammonium Nitrate-Fuel Oil Mixture*, U.S. Bureau of Mines Report of Investigation, U.S. Department of Interior Report of Investigation No. 7867, Pittsburgh Mining and Research Center, Pittsburgh, PA, 1974.

(c) *Compilation of Air Pollutant Emission Factors*, Second Edition (including Supplements 1-9), U.S. Environmental Protection Agency, Report AP-42, 1979.

(d) R. A. Wachter, "Fugitive Dust Levels from Stone Crushers," University of Cincinnati, Ohio, presented at 73rd Annual Meeting of the Air Pollution Control Association, Montreal, Quebec, June 1980.

(e) Particles less than 50 microns diameter.

(f) Dust Control Bulletin No. 304, American Air Filter Company, Inc., Louisvlle, KY.

(g) R. Bohn, T. Cuscino, Jr., and C. Cowherd, Jr., *Fugitive Emissions from Integrated Iron and Steel Plants*, Midwest Research Institute, Kansas City, Missouri, EPA-600/2-78-050, March 1978.

(h) R. J. Evans, "Methods and Costs of Dust Control in Stone Crushing Operations," U.S. Bureau of Mines Information Circular No. 8669, U.S. Department of the Interior, 1975.

(i) "Compilation of Past Practices and Interpretations by EPA Region VIII on Air Quality Mining," U.S. Environmental Protection Agency, Region VIII, December 1979.

(j) Design value.

(k) Personal Comm' nication, C. Evin, Sohio, March 1981.

(l) Design value. Cleaned fuel gas will contain 0.00 percent ammonia.

(m) Estimated.

(n) Based on sulfur species data from 1976 Union run on Utah shale, Reference J. Godlove to P. Smith memo of November 19, 1980.

(o) Fifty percent control on an annual basis.

(p) Worst daily rate. Assumes watering cannot be practiced due to unfavorable weather conditions.

(q) This is the GEP stack height used for modeling. Actual stack height will be 200 feet.

EMISSION POINTS:

1 MINING
2 IN-MINE CRUSHING
3 MINE CONVEYOR FEED BIN
4 STORAGE SILO FEED
5 SURFACE CRUSHING AND SCREENING
6 FINES CONVEYOR FEED
7 FINES CONVEYOR TRANSFER POINTS
8 FINES CONVEYOR DISCHARGE TO STACKER
9 UNION B CONVEYOR FEED
10 UNION B RETORT FEED
11 SUPERIOR CONVEYOR FEED
12 SUPERIOR RETORT FEED
13 UNION B RETORT DISCHARGE TO PROCESSED SHALE CONVEYOR
14 SUPERIOR RETORT DISCHARGE TO PROCESSED SHALE CONVEYOR
15 PROCESSED SHALE CONVEYOR DISCHARGE TO BIN
16 COARSE SHALE STOCKPILE
17 FINES STOCKPILE
18 PROCESSED SHALE STORAGE
19 UNION B RETORT – RECYCLE GAS HEATER
20 HYDROGEN PLANT REFORMER FURNACE
21 BOILER
22 HYDROTREATER REACTOR FEED FURNACE
23 FLARE PILOT
24 GAS TREATMENT PLANT
25 UNION B RAW SHALE OIL STORAGE
26 SUPERIOR RAW SHALE OIL STORAGE
27 SYNCRUDE PRODUCT OIL STORAGE
28 RECOVERED OIL TANK
29 DIESEL FUEL TANK
30 FUEL OIL TANK
31 NAPHTHA TANK

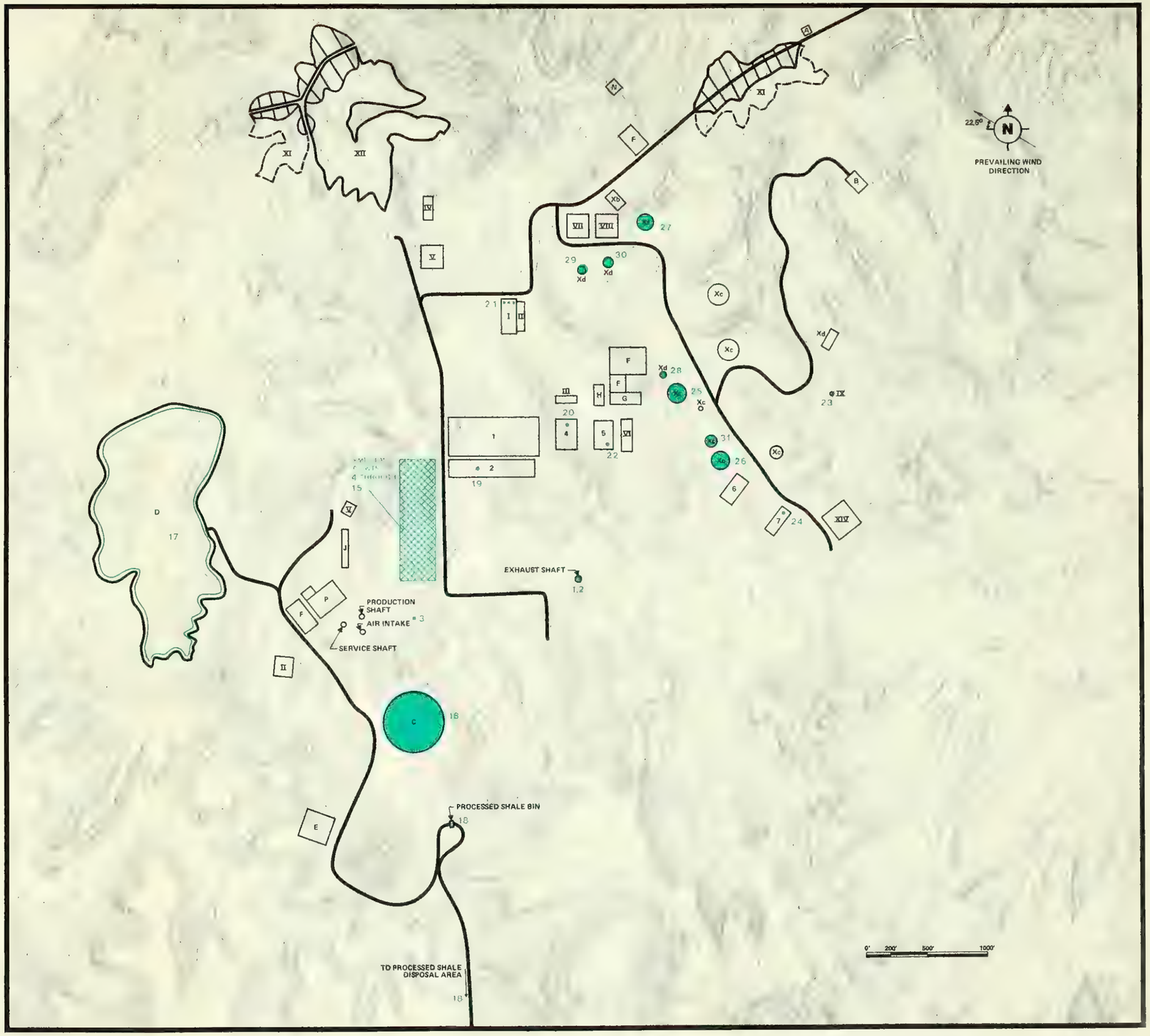


Figure 5-1 EMISSION POINTS PLOT PLAN – PHASE I

Table 5-2

PHASE II AIR POLLUTANT EMISSION INVENTORY

Emission Source	Operational Quantity	Pollutant	Emission Factor Without Control	Control Measure and Efficiency	Total Emission Rate		Emission Height (ft)	Number of Emission Points	Exhaust Diameter (ft)	Exhaust Temperature (°F)	Exhaust Volume (scfm)
					lb/day	t/yr					
1. Mining	Up to 93,500 TPSD	Particulate	0.018 lb/ton[a]	Wet suppression and baffled settling (80%)[a]	337	55	Surface	2	28	Ambient	6,000,000
	Up to 51,000 lb ANFO/day for blasting	CO	0.022 lb/lb ANFO[a,b]		1,122	184	(Contained in mine vent exhaust)				
		NO_x	0.012 lb/lb ANFO[a,b]		613	101					
	Up to 15,900 GPD diesel fuel for mine equipment	Particulate	22 lb/1000 gal[c]		350	57	(Contained in mine vent exhaust)				
		CO	90 lb/1000 gal[c]		1,431	235					
		HC	28 lb/1000 gal[c]		445	73					
		NO_x	428 lb/1000 gal[c]		6,805	1,118					
		SO_2	31 lb/1000 gal[c]		493	81					
2. In-Mine Crushing	Up to 47,000 TPSD to primary crusher	Particulate	0.02 lb/ton[d,e]	Wet suppression and baffled settling (80%)[a]	188	31	(Contained in mine vent exhaust)				
	Up to 93,500 TPSD to secondary crusher and screens	Particulate	6 gr/scf[f]	Baghouse (99.7%)[c] (15,000 scfm)	56	9	(Contained in mine vent exhaust)				
3. Mine Conveyor Surge Bin	Up to 93,500 TPSD	Particulate	4 gr/scf[f]	Baghouse (99.7%)[c]	20	3	50	1	2.5	Ambient	8,000
4. Mine Conveyor Transfer Points	Up to 66,000 TPSD (1 transfer point)	Particulate	0.009 lb/t[g]	Wet suppression (90%)[g,h]	59	10	Surface	1		Ambient	
5. Feed to Ph. I and II Storage Silos	93,500 TPSD	Particulate	4 gr/scf[f]	Baghouse (99.7%)[c]	25	4	50	2	1.5	Ambient	5,000 each
6. Ph. I and II Surface Crushing and Screening	93,500 TPSD	Particulate	7 gr/scf[f]	Baghouse (99.7%)[c]	130	21	30	1	2.5	Ambient	15,000
7. Fines Conveyor Feed (Ph. I and II Conveyors)	9,400 TPSD	Particulate	0.04 lb/t[g]	Wet suppression (90%)[g,h]	38	6.2	Surface	1			
8. Fines Conveyor Transfer Points (Ph. I and II Sections)	9,400 TPSD (4 transfer points)	Particulate	0.04 lb/t each[g]	Wet suppression (90%)[g,h]	152	25	Surface	4			
9. TOSCO Retort Feed Silos	9,350 TPSD	Particulate	3 gr/scf[f]	Baghouse (99.7%)[c]	9	1.5	50	1	1.5	Ambient	5,000

Table 5-2 (Continued)

Emission Source	Operational Quantity	Pollutant	Emission Factor Without Control	Control Measure and Efficiency	Total Emission Rate		Emission Height (ft)	Number of Emission Points	Exhaust Diameter (ft)	Exhaust Temperature (°F)	Exhaust Volume (scfm)
					lb/day	t/yr					
10. Union Conveyor Feed	46,400 TPSD	Particulate	0.006 lb/t[g]	Wet suppression (90%)[g,h]	28	3.5	Surface	4			
11. Union Retort Feed Silos	46,400 TPSD	Particulate	3 gr/scf[f]	Baghouse (99.7%)[c]	8	1.3	50	4	0.75	Ambient	1,000 each
12. Superior Conveyor Feed (Ph. I and II)	38,000 TPSD	Particulate	0.006 lb/t[g]	Wet suppression (90%)[g,h]	23	3.7	Surface	1			
13. Superior Retort Feed Bins/Silos	38,000 TPSD	Particulate	3 gr/scf[f]	Baghouse (99.7%)[c]	21	3.4	50	2	1.5	Ambient	5,000 each
					13	2.2	50	2	1.25	Ambient	3,200 each
14. Union Discharge to Processed Shale Conveyor	39,500 TPSD	Particulate	0.0001 lb/t[g]	Shale moisturized to 20% water	4	0.7	Surface	4			
15. TOSCO Discharge to Processed Shale Conveyor	8,000 TPSD	Particulate	0.0001 lb/t[g]	Shale moisturized to 20% water	1	0.1	Surface	1			
16. Superior (Ph. I) Discharge to Processed Shale Conveyor	11,000 TPSD	Particulate	0.0001 lb/t[g]	Shale moisturized to 20% water	1	0.2	Surface	1			
17. Superior (Ph. II) Discharge to Processed Shale Conveyor	31,900 TPSD	Particulate	0.0001 lb/t[g]	Shale moisturized to 20% water	2	0.3	Surface	2			
18. Processed Shale Conveyor Transfer Points	79,400 TPSD	Particulate	0.0003 lb/t[g]	Shale moisturized to 15% water	71	12	Surface	3			
19. Processed Shale Disposal											
a. Load-in	79,400 TPSD	Particulate	0.0003 lb/t[g]	Shale 15% water	24	4	Surface				
b. Grooming	60 scraper-hours/day	Particulate	16 lb/scraper-hour[i]	Watering (50%)[i,s]	960[t]	79	Surface				
c. Wind erosion	30 acres	Particulate	8,570 lb/acre-yr[g]	Compaction and chemical dust suppressants (85%)[i]	106	19	Surface				

Table 5-2 (Continued)

Emission Source	Operational Quantity	Pollutant	Emission Factor Without Control	Control Measure and Efficiency	Total Emission Rate		Emission Height (ft)	Number of Emission Points	Exhaust Diameter (ft)	Exhaust Temperature (°F)	Exhaust Volume (scfm)
					lb/day	t/yr					
20. Raw Shale Stockpile											
a. Load-in	2,700 TPSD	Particulate	0.009 lb/t[g]	Lowering well (75%)[g]	6	1	Surface				
b. Grooming	2,700 TPSD	Particulate	0.02 lb/t[g]	Watering (50%)[i,s]	54[t]	4.4	Surface				
c. Wind erosion of live storage	175,000 tons of shale	Particulate	0.32 lb/t-yr[g]	Watering (50%)[i,s]	153[t]	14	Surface				
d. Wind erosion of dead storage	1.8 million tons of shale	Particulate	0.32 lb/t-yr[g]	Sealing (95%)[g]	80	15	Surface				
21. Union B Recycle Gas Heater	685 MMBtu/hr shale oil; 275 MMBtu/hr high-Btu gas (112 Bbl/hr, 316,000 scf/hr)	Particulate	3 lb/10^3 gal + 15 lb/MMscf[c]	Upgraded shale oil, treated fuel gas, low-NO_x burners	452	74	200	4	4.25	300	44,900 each
		SO_2	0.284 lb/10^3 gal[c] + 140 lb/MMscf[n]		1,094	180					
		CO	5 lb/10^3 gal + 17 lb/MMscf[c]		693	114					
		HC	1 lb/10^3 gal + 3 lb/MMscf[c]		136	22					
		NO_x	31 lb/10^3 gal + 210 lb/MMscf[c]		5,092	836					
22. TOSCO Ball Heaters and Lift Pipes	241 MMBtu/hr high-Btu gas (276,000 scf/hr) 9,350 TPSD	SO_2	140 lb/MMscf[n]	Cyclone (93.8%)[c] and venturi scrubber (99.5%)[c] for particulate control. Incinerator for HC control (85%).[o] Treated fuel gas, upgraded shale oil, and low-NO_x burners	930	153	250	1	9.5	130	131,000 each
		NO_x	210 lb/MMscf[c]		1,391	228					
		CO	17 lb/MMscf[c]		113	19					
		HC	0.73 lb/ton-shale feed[o]		1,024	168					
		Particulate	64.5 gr/scf[p]		539	89					
23. TOSCO Elutriator	9,350 TPSD	Particulate (r)	1% feed[m,p]	Cyclone (93.8%)[c] and Venturi scrubber (99.5%)[c]	58	10	250	1	6.0	146	26,500
Processed Shale Moisturizer		Particulate	4 gr/scf[f,p]	Venturi scrubber (99.5%)[c]	103	17	(Combined with Elutriator Exhaust)			184	26,500
24. Hydrogen Plant Reformer Furnace (Ph. I)	383 MMBtu/hr shale oil; 53 MMBtu/hr high-Btu gas (63 Bbl/hr, 60,850 scf/hr)	Particulate	3 lb/10^3 gal + 15 lb/MMscf[c]	Upgraded shale oil, treated fuel gas, low-NO_x burners	212	35	135	1	5.75	330	75,300
		SO_2	0.284 lb/10^3 gal[c] + 140 lb/MMscf[n]		222	37					
		CO	5 lb/10^3 gal + 17 lb/MMscf[c]		342	56					
		HC	1 lb/10^3 gal + 3 lb/MMscf[c]		68	11					
		NO_x	31 lb/10^3 gal + 210 lb/MMscf[c]		2,275	374					
Hydrogen Plant Reformer Furnace (Ph. II)	759 MMBtu/hr shale oil; 43 MMBtu/hr high-Btu gas (125 Bbl/hr, 49,400 scf/hr)	Particulate	3 lb/10^3 gal + 15 lb/MMscf[c]	Upgraded shale oil, treated fuel gas, low-NO_x burners	395	65	188	2	5.75	330	85,000 each
		SO_2	0.284 lb/10^3 gal[c] + 140 lb/MMscf[n]		202	33					
		CO	5 lb/10^3 gal + 17 lb/MMscf[c]		650	107					
		HC	1 lb/10^3 gal + 3 lb/MMscf[c]		129	21					
		NO_x	31 lb/10^3 gal + 210 lb/MMscf[c]		4,155	682					

Table 5-2 (Continued)

Emission Source	Operational Quantity	Pollutant	Emission Factor Without Control	Control Measure and Efficiency	Total Emission Rate lb/day	Total Emission Rate t/yr	Emission Height (ft)	Number of Emission Points	Exhaust Diameter (ft)	Exhaust Temperature (°F)	Exhaust Volume (scfm)
25. Boiler and Steam Plant (Ph. I)	255 MMBtu/hr low-Btu gas; 28 MMBtu/hr upgr. shale oil (3.6 MMscf/hr, 4.6 Bbl/hr)	Particulate	0.03 lb/MMBtu[j]	Cleaned and treated fuel gas. Upgraded shale oil. Flue gas desulfurization.	204	34	250	1 stack, 3 flues	3.6	200	38,500 each
		SO_2	26.6 lb/MMscf[k] and 0.284 lb/10^3 gal[c]		464	76					
		CO	17 lb/MMscf and 5 lb/10^3 gal[c]		1,512	248					
		HC	1 lb/MMscf and 1 lb/10^3 gal[c]		91	15					
		NO_x	0.2 lb/MMBtu[l]		1,358	223					
Boiler and Power Plant (Ph. II)	485 MMBtu/hr low-Btu gas; 54 MMBtu/hr upgr. shale oil (6.9 MMscf/hr, 8.9 Bbl/hr)	Particulate	0.03 lb/MMBtu[j]	Cleaned and treated fuel gas. Upgraded shale oil. Flue gas desulfurization.	388	64	250	1 stack 2 flues	6.0	200	108,400 each
		SO_2	26.6 lb/MMscf[k] and 0.284 lb/10^3 gal[c]		885	145					
		CO	17 lb/MMscf and 5 lb/10^3 gal[c]		2,873	472					
		HC	1 lb/MMscf and 1 lb/10^3 gal[c]		175	29					
		NO_x	0.2 lb/MMBtu[l]		2,587	425					
26. Hydrotreater (Ph. I)	31 MMBtu/hr high-Btu gas (35,600 scf/hr)	Particulate	15 lb/MMscf[c]	Cleaned and treated fuel gas	13	2.1	100	1	2.25	300	5,700
		SO_2	140 lb/MMscf[n]		120	20					
		CO	17 lb/MMscf[c]		15	2.4					
		HC	3 lb/MMscf[c]		2.6	0.4					
		NO_x	230 lb/MMscf[c]		197	32					
Hydrotreater (Ph. II)	55.7 MMBtu/hr high-Btu gas (64,300 scf/hr)	Particulate	15 lb/MMscf[c]	Cleaned and treated fuel gas	23	3.7	100	1	3.0	300	9,800
		SO_2	140 lb/MMscf[n]		216	36					
		CO	17 lb/MMscf[c]		26	4.2					
		HC	3 lb/MMscf[c]		5	0.7					
		NO_x	230 lb/MMscf[c]		355	58					
27. Flare Pilot	2 MMBtu/hr high-Btu gas (2,300 scf/hr)	Particulate	15 lb/MMscf[c]	Cleaned and treated fuel gas	0.8	0.1	100	2	4.25	150	175 each
		SO_2	140 lb/MMscf[n]		8	1.3					
		CO	17 lb/MMscf[c]		0.9	0.1					
		HC	3 lb/MMscf[c]		0.2	0.03					
		NO_x	230 lb/MMscf[c]		13	2.0					
28. Gas Treatment Plant (Phase I)	Tail gas; 4 MMBtu/hr high-Btu gas (4,590 scf/hr)	SO_2	10,000-20,000 ppmv	Tail gas unit (<250 ppmv), treated high-Btu fuel gas	118	19	100[q]	1	1.75	300	2,200
		Particulate	15 lb/MMscf[c]		1.6	0.27					
		NO_x	230 lb/MMscf[c]		25	4.1					
		HC	3 lb/MMscf[c]		0.32	0.05					
		CO	17 lb/MMscf[c]		1.8	0.30					
Gas Treatment Plant (Phase II)	Tail gas; 13 MMBtu/hr high-Btu gas (14,900 scf/hr)	SO_2	10,000-20,000 ppmv	Tail gas unit (<250 ppmv), treated high-Btu fuel gas	440	72	100[q]	1	3.25	300	8,800
		Particulate	15 lb/MMscf[c]		5.2	0.86					
		NO_x	230 lb/MMscf[c]		82	14					
		HC	3 lb/MMscf[c]		1.1	0.18					
		CO	17 lb/MMscf[c]		6.0	0.99					
29. Crude Shale Oil Storage	660,000 Bbl raw shale oil	HC	API equation[c]	Floating roof tanks	553	100		4 tanks			

Table 5-2 (Continued)

Emission Source	Operational Quantity	Pollutant	Emission Factor Without Control	Control Measure and Efficiency	Total Emission Rate		Emission Height (ft)	Number of Emission Points	Exhaust Diameter (ft)	Exhaust Temperature (°F)	Exhaust Volume (scfm)
					lb/day	t/yr					
30. Synthetic Crude Oil Storage	525,000 Bbl upgraded shale oil	HC	API equation[c]	Floating roof tanks	423	76		3 tanks			
31. Recovered Oil (Slop) Tanks	15,000 Bbl	HC	API equation[c]	Floating roof tanks	33	5.9		2 tanks			
32. Diesel Fuel Tanks	40,000 Bbl diesel fuel	HC	API equation[c]	Fixed roof tanks	7.2	1.3		2 tanks			
33. Fuel Oil Tanks	68,000 Bbl fuel oil	HC	API equation[c]	Fixed roof tanks	0.5	0.1		2 tanks			
34. Naphtha Storage	60,000 Bbl	HC	API equation[c]	Floating roof tanks	20	3.5		1 tank			
35. Valves, Flanges, Pump Seals, etc.	57,000 Bbl/day	HC	50 lb/10^3 Bbl[c] production	Good housekeeping and and maintenance (50%)[m]	1,425	234					

Notes:

(a) P. W. Marshall, "Mine Dust and Fumes Control," Colony Development Operation, 1974. (See also EPA review of Colony PSD application.)
(b) R. F. Chaiken, E. B. Cook, and T. C. Ruhe, *Toxic Fumes from Explosives Ammonium Nitrate-Fuel Oil Mixture*, U.S. Bureau of Mines Report of Investigation, U.S. Department of Interior Report of Investigation No. 7867, Pittsburgh Mining and Research Center, Pittsburgh, PA, 1974.
(c) *Compilation of Air Pollutant Emission Factors*, Second Edition (including Supplements 1-9), U.S. Environmental Protection Agency, Report AP-42, 1979.
(d) R. A. Wachter, "Fugitive Dust Levels from Stone Crushers," University of Cincinnati, Ohio, presented at 73rd Annual Meeting of the Air Pollution Control Association, Montreal, Quebec, June 1980.
(e) Particles less than 50 microns diameter.
(f) Dust Control Bulletin No. 304, American Air Filter Company, Inc., Louisville, KY.
(g) R. Bohn, T. Cuscino, Jr., and C. Cowherd, Jr., *Fugitive Emissions from Integrated Iron and Steel Plants*, Midwest Research Institute, Kansas City, Missouri, EPA-600/2-78-050, March 1978.
(h) R. J. Evans, "Methods and Costs of Dust Control in Stone Crushing Operations," U.S. Bureau of Mines Information Circular No. 8669, U.S. Department of the Interior, 1975.
(i) "Compilation of Past Practices and Interpretations by EPA Region VIII on Air Quality Mining," U.S. Environmental Protection Agency, Region VIII, December 1979.
(j) Design value.
(k) Personal Communication, C. Evin, Sohio, March 1981.
(l) Design value. Cleaned fuel gas will contain 0.00 percent ammonia.
(m) Estimated.
(n) Based on sulfur species data from 1976 Union run on Utah shale, Reference J. Godlove to P. Smith memo of November 19, 1980.
(o) Based on Colony test data. See "Lift Pipe Hydrocarbon Emissions," Addendum No. 1, Colony PSD application.
(p) Based on Colony test data. See EPA review of Colony PSD application.
(q) This is the GEP stack height used for modeling. Actual stack height will be 200 feet.
(r) Pollutants in flue gases used for preheating are included in boiler plant emissions.
(s) Fifty percent control on an annual basis.
(t) Worst daily rate. Assumes watering cannot be practiced due to unfavorable weather conditions.

Table 5-3

PHASE III AIR POLLUTANT EMISSION INVENTORY

Emission Source	Operational Quantity	Pollutant	Emission Factor Without Control	Control Measure and Efficiency	Total Emission Rate		Emission Height (ft)	Number of Emission Points	Exhaust Diameter (ft)	Exhaust Temperature (°F)	Exhaust Volume (scfm)
					lb/day	t/yr					
1. Mining	Up to 176,000 TPSD	Particulate	0.018 lb/ton[a]	Wet suppression and baffled settling (80%)[a]	634	104	Surface	4	28	Ambient	11,250,000
	Up to 96,500 lb ANFO/day for blasting	CO NO_x	0.022 lb/lb ANFO[a,b] 0.012 lb/lb ANFO[a,b]		2,123 1,158	349 190	(Contained in mine vent exhaust)				
	Up to 30,000 GPD diesel fuel for mine equipment	Particulate CO HC NO_x SO_2	22 lb/1000 gal[c] 90 lb/1000 gal[c] 28 lb/1000 gal[c] 428 lb/1000 gal[c] 31 lb/1000 gal[c]		660 2,700 840 12,840 930	108 443 138 2,109 153	(Contained in mine vent exhaust)				
2. In-Mine Crushing	Up to 89,000 TPSD to primary crusher	Particulate	0.02 lb/ton[d,e]	Wet suppression and baffled settling (80%)[a]	352	58	(Contained in mine vent exhaust)				
	Up to 176,000 TPSD to secondary crusher and screens	Particulate	6 gr/scf[f]	Baghouse (99.7%)[c] (30,000 scfm)	111	18	(Contained in mine vent exhaust)				
3. Mine Conveyor Surge Bin	Up to 176,000 TPSD	Particulate	4 gr/scf[f]	Baghouse (99.7%)[c]	37	6	50	1	2.5	Ambient	15,000
4. Mine Conveyor Transfer Points	Up to 149,000 TPSD (1 transfer point)	Particulate	0.009 lb/t[g]	Wet suppression (90%)[g,h]	134	22	Surface	1		Ambient	
5. Feed to Ph. I and II Storage Silos	93,500 TPSD	Particulate	4 gr/scf[f]	Baghouse (99.7%)[c]	25	4	50	2	1.5	Ambient	5,000 each
6. Feed to Ph. III Storage Silo	82,400 TPSD	Particulate	4 gr/scf[f]	Baghouse (99.7%)[c]	25	4	50	1	2.25	Ambient	10,000
7. Ph. I and II Surface Crushing and Screening	93,500 TPSD	Particulate	7 gr/scf[f]	Baghouse (99.7%)[c]	130	21	30	1	2.5	Ambient	15,000
8. Ph. III Surface Crushing and Screening	82,400 TPSD	Particulate	7 gr/scf[f]	Baghouse (99.7%)[c]	130	21	30	1	2.5	Ambient	15,000
9. Fines Reclaim Conveyor Transfer Points	900 TPSD (2 transfer points)	Particulate	0.04 lb/t-transfer[g]	Wet suppression (90%)[g,h]	7	1.2	Surface	2			

Emission Source	Operational Quantity	Pollutant	Emission Factor Without Control	Control Measure and Efficiency	Total Emission Rate		Emission Height (ft)	Number of Emission Points	Exhaust Diameter (ft)	Exhaust Temperature (°F)	Exhaust Volume (scfm)
					lb/day	t/yr					
10. Fines Conveyor Feed (Ph. I and II Conveyors)	9,400 TPSD	Particulate	0.04 lb/t[g]	Wet suppression (90%)[g,h]	38	6.2	Surface	1			
11. Fines Conveyor Feed (Ph. III Conveyor)	8,200 TPSD	Particulate	0.04 lb/t[g]	Wet suppression (90%)[g,h]	33	5.4	Surface	1			
12. Fines Conveyor Transfer Points (Ph. I and II Sections)	9,400 TPSD (4 transfer points)	Particulate	0.04 lb/t each[g]	Wet suppression (90%)[g,h]	152	25	Surface	4			
13. Fines Conveyor Transfer Points (Ph. III Section)	8,200 TPSD (4 transfer points)	Particulate	0.04 lb/t each[g]	Wet suppression (90%)[g,h]	131	21.5	Surface	4			
14. TOSCO Retort Feed Silos	18,500 TPSD	Particulate	3 gr/scf[f]	Baghouse (99.7%)[c]	19	3	50	2	1.5	Ambient	5,000 each
15. Union Conveyor Feed	46,400 TPSD	Particulate	0.006 lb/t[g]	Wet suppression (90%)[g,h]	28	3.5	Surface	4			
16. Union Retort Feed Silos	46,400 TPSD	Particulate	3 gr/scf[f]	Baghouse (99.7%)[c]	8	1.3	50	4	0.75	Ambient	1,000 each
17. Superior Conveyor Feed (Ph. I and II)	38,000 TPSD	Particulate	0.006 lb/t[g]	Wet suppression (90%)[g,h]	23	3.7	Surface	1			
18. Superior Conveyor Feed (Ph. III)	74,000 TPSD	Particulate	0.006 lb/t[g]	Wet suppression (90%)[g,h]	44	7.3	Surface	1			
19. Superior Conveyor Transfer Point	74,000 TPSD	Particulate	0.006 lb/t[g]	Wet suppression (90%)[g,h]	44	7.3	Surface	1			
20. Superior Retort Feed Bins/Silos	112,000 TPSD	Particulate	3 gr/scf[f]	Baghouse (99.7%)[c]	52	8.5	50	5	1.5	Ambient	5,000 each
					33	5.5	50	5	1.25	Ambient	3,200 each
21. Union Discharge to Processed Shale Conveyor	39,500 TPSD	Particulate	0.0001 lb/t[g]	Shale moisturized to 20% water	4	0.7	Surface	4			
22. TOSCO Discharge to Processed Shale Conveyor	15,000 TPSD	Particulate	0.0001 lb/t[g]	Shale moisturized to 20% water	2	0.3	Surface	2			
23. Superior (Ph. I) Discharge to Processed Shale Conveyor	11,000 TPSD	Particulate	0.0001 lb/t[g]	Shale moisturized to 20% water	1	0.2	Surface	1			

Emission Source	Operational Quantity	Pollutant	Emission Factor Without Control	Control Measure and Efficiency	Total Emission Rate		Emission Height (ft)	Number of Emission Points	Exhaust Diameter (ft)	Exhaust Temperature (°F)	Exhaust Volume (scfm)
					lb/day	t/yr					
24. Superior (Ph. II and III) Discharge to Processed Shale Conveyor	84,000 TPSD	Particulate	0.0001 lb/t[g]	Shale moisturized to 20% water	8	1.3	Surface	4			
25. Processed Shale Conveyor Transfer Points	149,500 TPSD	Particulate	0.0003 lb/t[g]	Shale moisturized to 15% water	135	22	Surface	3			
26. Processed Shale Disposal											
a. Load-in	149,500 TPSD	Particulate	0.0003 lb/t[g]	Shale 15% water	45	7.3	Surface				
b. Grooming	112 scraper-hours/day	Particulate	16 lb/scraper-hour[i]	Watering (50%)[i,s]	1,792[t]	147	Surface				
c. Wind erosion	30 acres	Particulate	8,570 lb/acre-yr[g]	Compaction and chemical dust suppressants (85%)[i]	106	19	Surface				
27. Fines Storage											
a. Reclaim	1,800 TPSD	Particulate	0.026 lb/t[g]	Watering (50%)[i,s]	47[t]	3.9	Surface				
b. Wind erosion	5 acres exposed	Particulate	6,428 lb/acre-yr[g]	Watering (50%)[i,s]	88[t]	8.0	Surface				
c. Traffic	1,800 TPSD	Particulate	0.12 lb/t[g]	Watering (50%)[i,s]	216[t]	18	Surface				
28. Raw Shale Stockpile											
a. Load-in	5,000 TPSD	Particulate	0.009 lb/t[g]	Lowering well (75%)[g]	11	1.8	Surface				
b. Grooming	5,000 TPSD	Particulate	0.02 lb/t[g]	Watering (50%)[i,s]	100[t]	8.2	Surface				
c. Wind erosion of live storage	175,000 tons of shale	Particulate	0.32 lb/t-yr[g]	Watering (50%)[i,s]	153[t]	14	Surface				
d. Wind erosion of dead storage	2.8 million tons of shale	Particulate	0.32 lb/t-yr[g]	Sealing (95%)[g]	124	23	Surface				
29. Union B Recycle Gas Heater	928 MMBtu/hr shale oil; 32 MMBtu/hr high-Btu gas (152 Bbl/hr, 36,100 scf/hr)	Particulate SO_2 CO HC NO_x	3 lb/10^3 gal + 15 lb/MMscf[c] 0.284 lb/10^3 gal[c] + 140 lb/MMscf[n] 5 lb/10^3 gal + 17 lb/MMscf[c] 1 lb/10^3 gal + 3 lb/MMscf[c] 31 lb/10^3 gal + 210 lb/MMscf[c]	Upgraded shale oil, treated fuel gas, low-NO_x burners	473 165 781 156 4,932	77 27 128 26 810	200	4	4.25	300	45,100 each
30. TOSCO Ball Heaters and Lift Pipes	417 MMBtu/hr shale oil; 62 MMBtu/hr high-Btu gas (68.5 Bbl/hr, 69,900 scf/hr) 18,500 TPSD	SO_2 NO_x CO HC Particulate	0.28 lb/10^3 gal[c] and 140 lb/MMscf[n] 31 lb/10^3 gal and 210 lb/MMscf[c] 5 lb/10^3 gal and 17 lb/MMscf[c] 0.73 lb/ton-shale feed[o] 64.5 gr/scf[p]	Cyclone (93.8%)[c] and venturi scrubber (99.5%)[c] for particulate control. Incinerator for HC control (85%).[o] Treated fuel gas, upgraded shale oil, and low-NO_x burners	255 2,492 374 2,026 1,080	42 409 61 333 177	250	2	9.5	130	131,000 each

Table 5-3 (Continued)

Emission Source	Operational Quantity	Pollutant	Emission Factor Without Control	Control Measure and Efficiency	Total Emission Rate lb/day	Total Emission Rate t/yr	Emission Height (ft)	Number of Emission Points	Exhaust Diameter (ft)	Exhaust Temperature (°F)	Exhaust Volume (scfm)
31. TOSCO Elutriators	18,500 TPSD	Particulate (r)	1% feed[m,p]	Cyclone (93.8%)[c] and Venturi scrubber (99.5%)[c]	115	19	250	2	6.0	146	26,500 each
Processed Shale Moisturizers		Particulate	4 gr/scf[f,p]	Venturi scrubber (99.5%)[c]	206	34	(Combined with Elutriator Exhaust)			184	26,500 each
32. Hydrogen Plant Reformer Furnace (Ph. I)	420 MMBtu/hr shale oil; 16 MMBtu/hr high-Btu gas (69 Bbl/hr, 18,100 scf/hr)	Particulate	3 lb/10^3 gal + 15 lb/MMscf[c]	Upgraded shale oil, treated fuel gas, low-NO_x burners	215	35	135	1	5.75	330	85,000
		SO_2	0.284 lb/10^3 gal[c] + 140 lb/MMscf[n]		81	13					
		CO	5 lb/10^3 gal + 17 lb/MMscf[c]		355	58					
		HC	1 lb/10^3 gal + 3 lb/MMscf[c]		71	12					
		NO_x	31 lb/10^3 gal + 210 lb/MMscf[c]		2,247	369					
Hydrogen Plant Reformer Furnace (Ph. II)	785 MMBtu/hr shale oil; 26 MMBtu/hr high-Btu gas (129 Bbl/hr, 29,300 scf/hr)	Particulate	3 lb/10^3 gal + 15 lb/MMscf[c]	Upgraded shale oil, treated fuel gas, low-NO_x burners	401	66	188	2	5.75	330	76,100 each
		SO_2	0.284 lb/10^3 gal[c] + 140 lb/MMscf[n]		135	22					
		CO	5 lb/10^3 gal + 17 lb/MMscf[c]		662	109					
		HC	1 lb/10^3 gal + 3 lb/MMscf[c]		132	22					
		NO_x	31 lb/10^3 gal + 210 lb/MMscf[c]		4,179	686					
Hydrogen Plant Reformer Furnace (Ph. III)	785 MMBtu/hr shale oil; 26 MMBtu/hr high-Btu gas (129 Bbl/hr, 29,300 scf/hr)	Particulate	3 lb/10^3 gal + 15 lb/MMscf[c]	Upgraded shale oil, treated fuel gas, low-NO_x burners	401	66	250	2	5.75	330	76,300 each
		SO_2	0.284 lb/10^3 gal[c] + 140 lb/MMscf[n]		135	22					
		CO	5 lb/10^3 gal + 17 lb/MMscf[c]		662	109					
		HC	1 lb/10^3 gal + 3 lb/MMscf[c]		132	22					
		NO_x	31 lb/10^3 gal + 210 lb/MMscf[c]		4,179	686					
33. Boiler and Steam Plant (Ph. I)	255 MMBtu/hr low-Btu gas; 28 MMBtu/hr upgr. shale oil (3.6 MMscf/hr, 4.6 Bbl/hr)	Particulate	0.03 lb/MMBtu[j]	Cleaned and treated fuel gas. Upgraded shale oil. Flue gas desulfurization.	204	34	250	1 stack, 3 flues	3.6	200	38,500 each flue
		SO_2	26.6 lb/MMscf[k] and 0.284 lb/10^3 gal[c]		464	76					
		CO	17 lb/MMscf and 5 lb/10^3 gal[c]		1,512	248					
		HC	1 lb/MMscf and 1 lb/10^3 gal[c]		91	15					
		NO_x	0.2 lb/MMBtu[l]		1,358	223					
Boiler and Power Plant (Ph. II)	485 MMBtu/hr low-Btu gas; 54 MMBtu/hr upgr. shale oil (6.9 MMscf/hr, 8.9 Bbl/hr)	Particulate	0.03 lb/MMBtu[j]	Cleaned and treated fuel gas. Upgraded shale oil. Flue gas desulfurization.	388	64	250	1 stack 2 flues	6.0	200	108,400 each flue
		SO_2	26.6 lb/MMscf[k] and 0.284 lb/10^3 gal[c]		885	145					
		CO	17 lb/MMscf and 5 lb/10^3 gal[c]		2,873	472					
		HC	1 lb/MMscf and 1 lb/10^3 gal[c]		175	29					
		NO_x	0.2 lb/MMBtu[l]		2,587	425					
Boiler and Power Plant (Ph. III)	1,455 MMBtu/hr low-Btu gas; 161 MMBtu/hr upgr. shale oil (20.8 MMscf/hr, 26.4 Bbl/hr)	Particulate	0.03 lb/MMBtu[j]	Cleaned and treated fuel gas. Upgraded shale oil. Flue gas desulfurization.	1,163	191	250	1 stack, 4 flues	7.4	200	163,000 each flue
		SO_2	26.6 lb/MMscf[k] and 0.284 lb/10^3 gal[c]		2,657	436					
		CO	17 lb/MMscf and 5 lb/10^3 gal[c]		8,619	1,416					
		HC	1 lb/MMscf and 1 lb/10^3 gal[c]		526	86					
		NO_x	0.2 lb/MMBtu[l]		7,755	1,274					
34. Hydrotreater (Ph. I)	31 MMBtu/hr high-Btu gas (34,950 scf/hr)	Particulate	15 lb/MMscf[c]	Cleaned and treated fuel gas	13	2.1	100	1	1.75	300	5,700
		SO_2	140 lb/MMscf[n]		117	19					
		CO	17 lb/MMscf[c]		14	2.3					
		HC	3 lb/MMscf[c]		2.5	0.4					
		NO_x	230 lb/MMscf[c]		193	32					
Hydrotreater (Ph. II)	55.7 MMBtu/hr high-Btu gas (62,800 scf/hr)	Particulate	15 lb/MMscf[c]	Cleaned and treated fuel gas	23	3.7	100	1	3.0	300	9,800
		SO_2	140 lb/MMscf[n]		211	35					
		CO	17 lb/MMscf[c]		26	4.2					
		HC	3 lb/MMscf[c]		5	0.7					
		NO_x	230 lb/MMscf[c]		347	57					

Emission Source	Operational Quantity	Pollutant	Emission Factor Without Control	Control Measure and Efficiency	Total Emission Rate		Emission Height (ft)	Number of Emission Points	Exhaust Diameter (ft)	Exhaust Temperature (°F)	Exhaust Volume (scfm)
					lb/day	t/yr					
Hydrotreater (Ph. III)	63.5 MMBtu/hr high-Btu gas (71,600 scf/hr)	Particulate	15 lb/MMscf[c]	Cleaned and treated fuel gas	26	4.2	100	1	3.25	300	11,100
		SO_2	140 lb/MMscf[n]		241	40					
		CO	17 lb/MMscf[c]		29	4.8					
		HC	3 lb/MMscf[c]		5	0.8					
		NO_x	230 lb/MMscf[c]		395	65					
35. Flare Pilot	3 MMBtu/hr high-Btu gas (3,380 scf/hr)	Particulate	15 lb/MMscf[c]	Cleaned and treated fuel gas	1.2	0.2	100	3	4.25	150	175 each
		SO_2	140 lb/MMscf[n]		12	1.8					
		CO	17 lb/MMscf[c]		1.4	0.2					
		HC	3 lb/MMscf[c]		0.2	0.03					
		NO_x	230 lb/MMscf[c]		19	3.0					
36. Gas Treatment Plant (Phase I)	Tail gas; 4 MMBtu/hr high-Btu gas (4,510 scf/hr)	SO_2	10,000-20,000 ppmv	Tail gas unit (<250 ppmv), treated high-Btu fuel gas	118	19	100[q]	1	1.75	300	2,200
		Particulate	15 lb/MMscf[c]		1.6	0.27					
		NO_x	230 lb/MMscf[c]		25	4.1					
		HC	3 lb/MMscf[c]		0.32	0.05					
		CO	17 lb/MMscf[c]		1.8	0.30					
Gas Treatment Plant (Phase II)	Tail gas; 13 MMBtu/hr high-Btu gas (14,660 scf/hr)	SO_2	10,000-20,000 ppmv	Tail gas unit (<250 ppmv), treated high-Btu fuel gas	440	72	100[q]	1	3.25	300	8,800
		Particulate	15 lb/MMscf[c]		5.2	0.86					
		NO_x	230 lb/MMscf[c]		81	13					
		HC	3 lb/MMscf[c]		1.1	0.18					
		CO	17 lb/MMscf[c]		6.0	0.99					
Gas Treatment Plant (Phase III)	Tail gas; 11 MMBtu/hr high-Btu gas (12,400 scf/hr)	SO_2	10,000-20,000 ppmv	Tail gas unit (<250 ppmv), treated high-Btu fuel gas	315	52	100[q]	1	2.75	300	6,000
		Particulate	15 lb/MMscf[c]		4.4	0.73					
		NO_x	230 lb/MMscf[c]		69	11					
		HC	3 lb/MMscf[c]		0.90	0.15					
		CO	17 lb/MMscf[c]		5.1	0.84					
37. Crude Shale Oil Storage	1.41 MMBbl raw shale oil	HC	API equation[c]	Floating roof tanks	1,073	195		7 tanks			
38. Synthetic Crude Oil Storage	1.25 MMBbl upgraded shale oil	HC	API equation[c]	Floating roof tanks	941	170		6 tanks			
39. Recovered Oil (Slop) Tanks	25,000 Bbl	HC	API equation[c]	Floating roof tanks	55	9.6		3 tanks			
40. Diesel Fuel Tanks	67,000 Bbl diesel fuel	HC	API equation[c]	Fixed roof tanks	12	2.2		3 tanks			
41. Fuel Oil Tanks	166,000 Bbl fuel oil	HC	API equation[c]	Fixed roof tanks	1.3	0.24		3 tanks			
42. Naphtha Storage	60,000 Bbl	HC	API equation[c]	Floating roof tanks	20	3.5		1 tank			
43. Valves, Flanges, Pump Seals, etc.	100,000 Bbl/day	HC	50 lb/10^3 Bbl[c] production	Good housekeeping and and maintenance (50%)[m]	2,500	411					

Notes:

(a) P. W. Marshall, "Mine Dust and Fumes Control," Colony Development Operation, 1974. (See also EPA review of Colony PSD application.)
(b) R. F. Chaiken, E. B. Cook, and T. C. Ruhe, *Toxic Fumes from Explosives Ammonium Nitrate-Fuel Oil Mixture*, U.S. Bureau of Mines Report of Investigation, U.S. Department of Interior Report of Investigation No. 7867, Pittsburgh Mining and Research Center, Pittsburgh, PA, 1974.
(c) *Compilation of Air Pollutant Emission Factors*, Second Edition (including Supplements 1-9), U.S. Environmental Protection Agency, Report AP-42, 1979.
(d) R. A. Wachter, "Fugitive Dust Levels from Stone Crushers," University of Cincinnati, Ohio, presented at 73rd Annual Meeting of the Air Pollution Control Association, Montreal, Quebec, June 1980.
(e) Particles less than 50 microns diameter.
(f) Dust Control Bulletin No. 304, American Air Filter Company, Inc., Louisville, KY.
(g) R. Bohn, T. Cuscino, Jr., and C. Cowherd, Jr., *Fugitive Emissions from Integrated Iron and Steel Plants*, Midwest Research Institute, Kansas City, Missouri, EPA-600/2-78-050, March 1978.
(h) R. J. Evans, "Methods and Costs of Dust Control in Stone Crushing Operations," U.S. Bureau of Mines Information Circular No. 8669, U.S. Department of the Interior, 1975.
(i) "Compilation of Past Practices and Interpretations by EPA Region VIII on Air Quality Mining," U.S. Environmental Protection Agency, Region VIII, December 1979.
(j) Design value.
(k) Personal Communication, C. Evin, Sohio, March 1981.
(l) Design value. Cleaned fuel gas will contain 0.00 percent ammonia.
(m) Estimated.
(n) Based on sulfur species data from 1976 Union run on Utah shale, Reference J. Godlove to P. Smith memo of November 19, 1980.
(o) Based on Colony test data. See "Lift Pipe Hydrocarbon Emissions," Addendum No. 1, Colony PSD application.
(p) Based on Colony test data. See EPA review of Colony PSD application.
(q) This is the GEP stack height used for modeling. Actual stack height will be 200 feet.
(r) Pollutants in flue gases used for preheating are included in boiler plant emissions.
(s) Fifty percent control on an annual basis.
(t) Worst daily rate. Assumes watering cannot be practiced due to unfavorable weather conditions.

EMISSION POINTS:

1 MINING
2 IN-MINE CRUSHING
3 MINE CONVEYOR SURGE BIN
4 MINE CONVEYOR TRANSFER POINTS
5 FEED TO PHASE I AND II STORAGE SILOS
6 FEED TO PHASE III STORAGE SILO
7 PHASE I AND II SURFACE CRUSHING AND SCREENING
8 PHASE III SURFACE CRUSHING AND SCREENING
9 FINES RECLAIM CONVEYOR TRANSFER POINTS
10 FINES CONVEYOR FEED (PHASE I AND II CONVEYORS)
11 FINES CONVEYOR FEED (PHASE III CONVEYOR)
12 FINES CONVEYOR TRANSFER POINTS (PHASE I AND II SECTIONS)
13 FINES CONVEYOR TRANSFER POINTS (PHASE III SECTION)
14 TOSCO II RETORT FEED BINS
15 UNION B CONVEYOR FEED
16 UNION B RETORT FEED BINS
17 SUPERIOR CONVEYOR FEED (PHASES I AND II)
18 SUPERIOR CONVEYOR FEED (PHASE III)
19 SUPERIOR CONVEYOR TRANSFER POINT
20 SUPERIOR RETORT FEED BINS
21 UNION B DISCHARGE TO PROCESSED SHALE CONVEYOR
22 TOSCO II DISCHARGE TO PROCESSED SHALE CONVEYOR
23 SUPERIOR (PHASE I) DISCHARGE TO PROCESSED SHALE CONVEYOR
24 SUPERIOR (PHASES II AND III) DISCHARGE TO PROCESSED SHALE CONVEYOR
25 PROCESSED SHALE CONVEYOR TRANSFER POINTS
26 PROCESSED SHALE STORAGE
27 FINES STORAGE
28 EMERGENCY STOCKPILE
29 UNION B RECYCLE GAS HEATERS
30 TOSCO II BALL HEATERS AND LIFT PIPES
31 TOSCO II ELUTRIATORS AND PROCESSED SHALE MOISTURIZERS
32 HYDROGEN PLANT REFORMER FURNACE (PHASES I, II, AND III)
33 BOILER AND POWER PLANT (PHASES I, II, AND III)
34 HYDROTREATER (PHASES I, II, AND III)
35 FLARE PILOT
36 GAS TREATMENT PLANT (PHASES I, II, AND III)
37 RAW SHALE OIL STORAGE
38 PRODUCT OIL STORAGE
39 RECOVERED OIL (SLOP) TANKS
40 DIESEL FUEL TANKS
41 FUEL OIL TANKS
42 NAPHTHA STORAGE

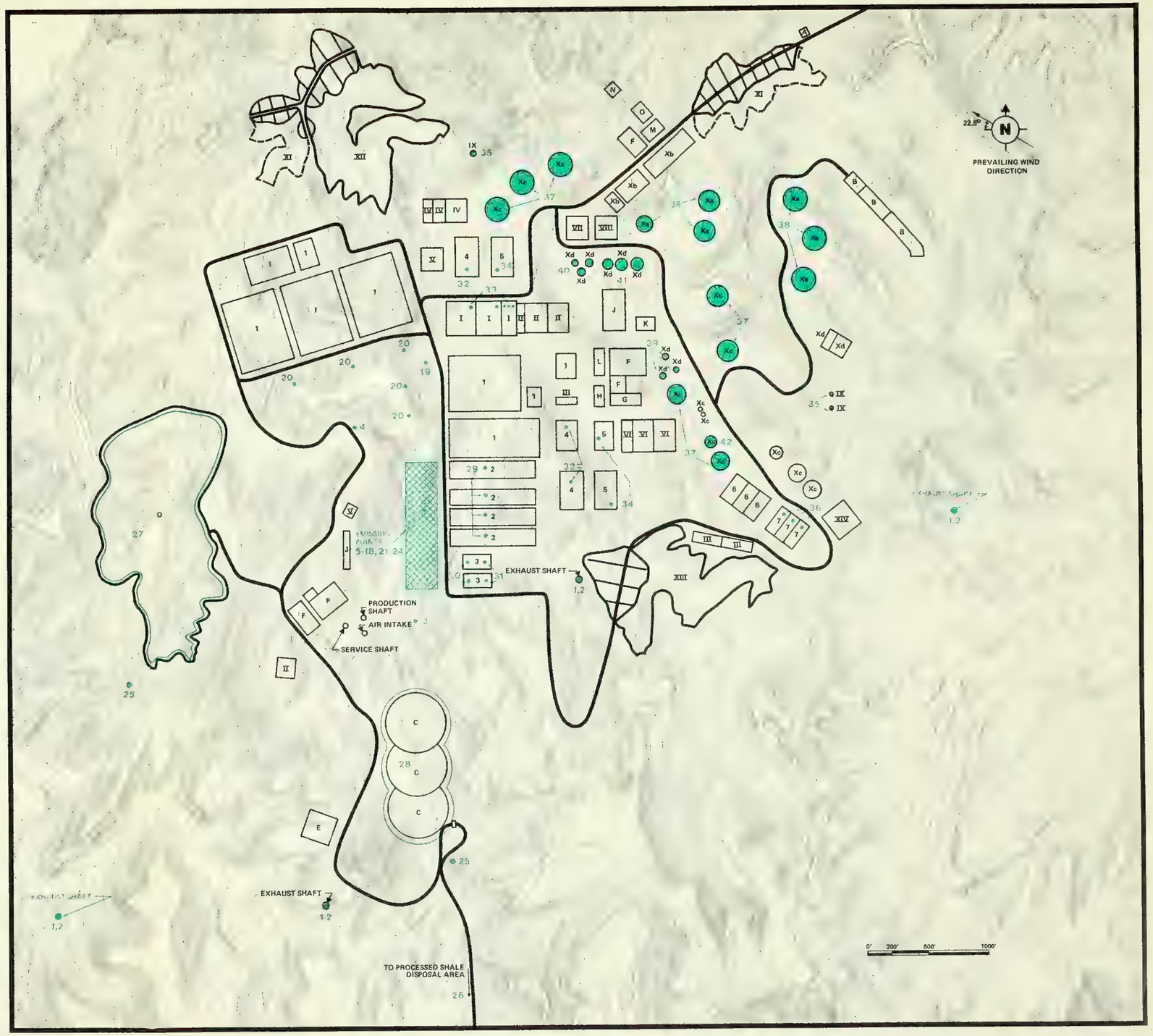


Figure 5-2 EMISSION POINTS PLOT PLAN – PHASE III

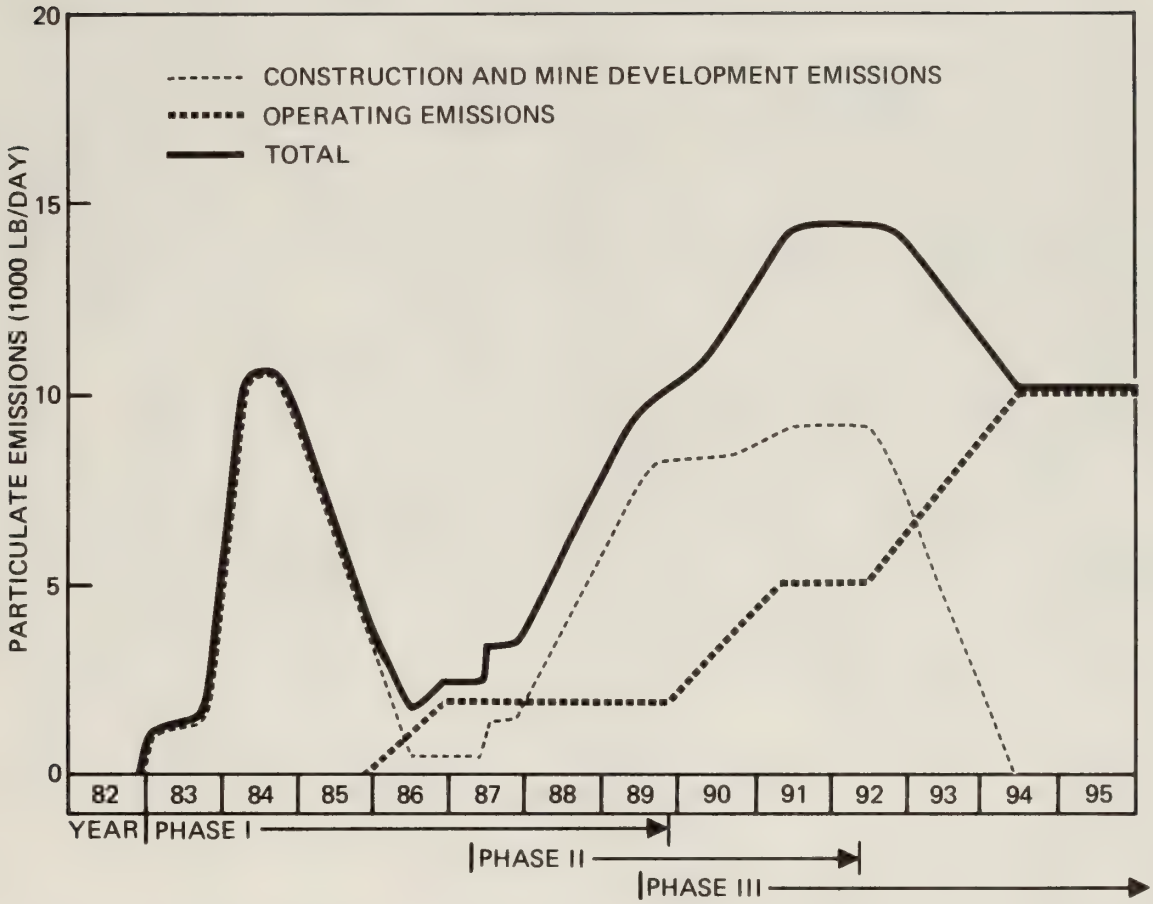


Figure 5-3 DAILY PARTICULATE EMISSIONS FOR PROJECT CONSTRUCTION AND OPERATION

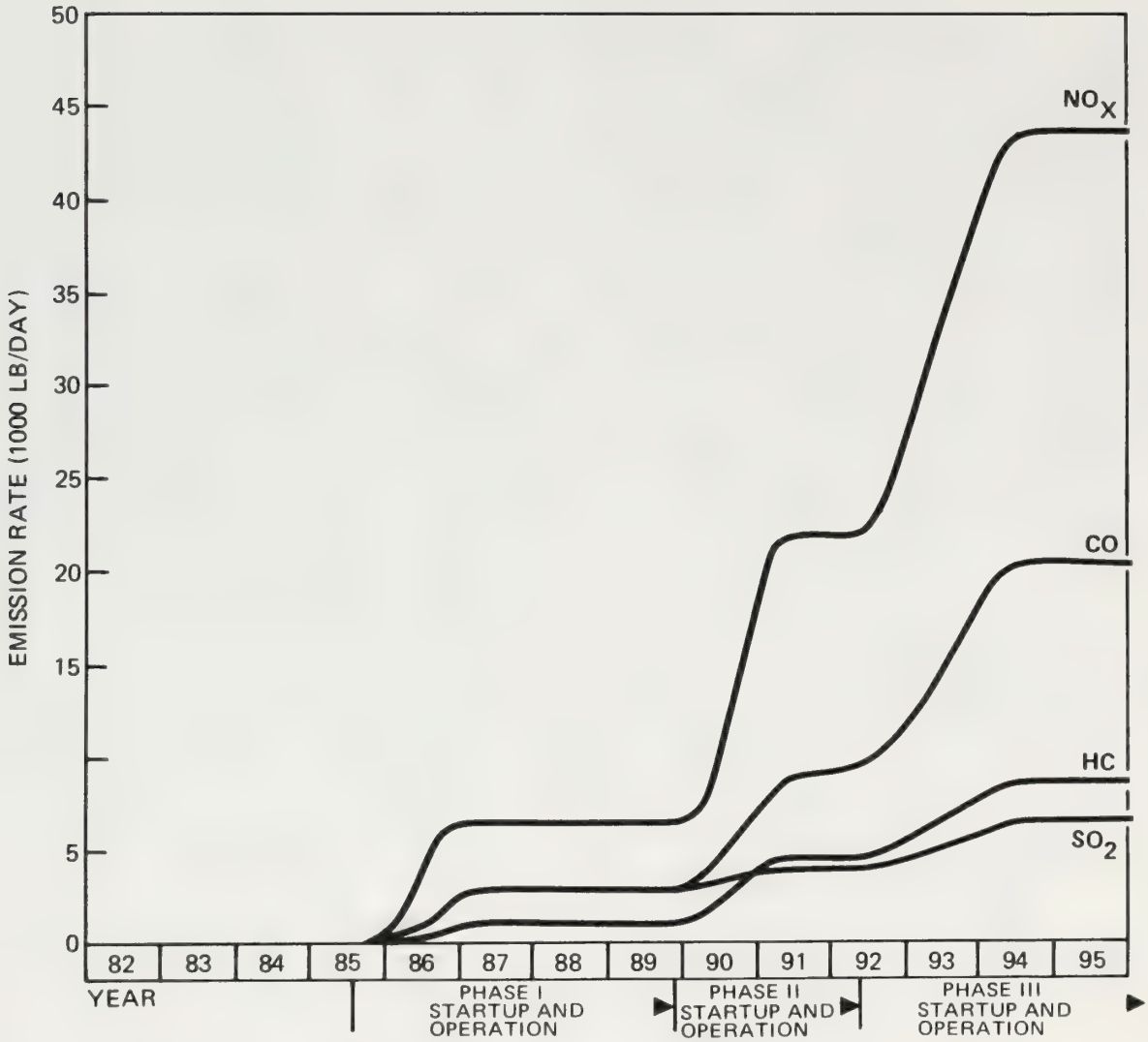


Figure 5-4 DAILY NO_X, SO_2, CO, AND HC EMISSIONS FOR PROJECT OPERATION

Based on the above concentrations of fluorides in the shale, it is estimated that about 0.24 TPY of fluorides will be contained in the dust generated from Phase I operations. In Phase III, fluorides contained in dust emissions are projected to increase to about 1.1 TPY.

In addition to fluorides emitted due to shale mining, handling, and storage operations, small quantities may also be released to the atmosphere through the combustion of fuel oils that contain trace concentrations of fluorides. Fluoride concentrations in the fuel oil are expected to be less than 1 ppm (Ref. 5-2). Combining this value with the Phase I fuel oil consumption rate gives a potential emission rate of 0.13 TPY. Phase III emissions from the combustion of fuel oil are estimated to amount to 0.76 TPY.

Summing the above emission estimates results in a total Phase I fluoride emission rate of 0.37 TPY. Phase III fluoride emissions are estimated to amount to 1.8 TPY.

5.2.2 Asbestos

Asbestos is the generic term given to a number of naturally occurring, crystalline mineral hydrated silicates. It occurs in a fibrous state and is formed by the metamorphosis of serpentine and amphibole minerals. Emissions of asbestos in this country occur almost exclusively from the asbestos manufacturing industry, including the mining and milling of asbestos and the production of asbestos-containing materials. To a much lesser extent, minor amounts of this material may be emitted as a result of the end use of various asbestos-containing materials.

Based on laboratory analyses of the mineral components of the Green River oil shales, the ore mined at the White River Shale Project is not expected to contain detectable levels of the asbestos compounds. Therefore, asbestos emissions originating from the raw oil shale are not expected to occur.

One potential source of emissions resulting from the end use of asbestos is the erosion of internal insulation in boiler breeching and ducts. Because of the hazardous nature of asbestos and because other insulating materials are available, the use of asbestos-containing materials that could be subject to erosion will be avoided.

Based on the foregoing discussion, it is estimated that asbestos emissions will be nil.

5.2.3 Beryllium

Beryllium is a grayish-white, hard, light metal with a melting point of 1,278C and a boiling point of 2,970C. Compounds of beryllium are known to be present in the earth's surface rocks in trace concentrations of about 2.8 ppm (as beryllium) on the average (Ref. 5-2). Potential sources of beryllium at the proposed facility that could result in trace emissions include dust from mining operations, particulate in flue gases, and dust from processed shale disposal.

In general, it has been found that beryllium concentrations in oil shale are about one-half of that of the earth's crust (Ref. 5-2). Analyses of the WRSP oil shale indicate that beryllium concentrations in both the raw and the processed shale are below 1 ppm; thus, emissions of beryllium are expected to be near zero.

5.2.4 Mercury

Mercury remains in liquid form over a temperature range of minus 39C to 357C. It is known to form a variety of relatively volatile compounds under combustion and pyrolysis conditions. Because of its volatility, a portion of any mercury or mercury compound present in the raw oil shale could be expected to be present in the retort offgas.

The earth's average crustal abundance of mercury is 0.8 ppm (Ref. 5-2). Testing of Utah oil shale has indicated that mercury concentrations in the raw shale are below detection levels (less than 0.5 ppm). Because of the low concentrations in the raw shale, emissions of mercury are expected to be negligible.

5.2.5 Vinyl Chloride

Vinyl chloride (C_2H_3Cl) is an anthropogenic gas with a boiling point of minus 13.9C. Although combustion systems are sources of small quantities of organic compounds, conditions in the combustion environment are extremely unfavorable for the formation of vinyl chloride.

No data could be located that suggest that vinyl chloride is present in combustion flue gases. However, data for C_3 alkanes obtained by chromatograph indicate that about 0.5 to 0.9 pound of C_3 hydrocarbons per 1,000 MMBtu are emitted when burning oil or gas (Ref. 5-3). As the boiling point of the vinyl chloride is minus 13.9C, it could be reported and included in the range of C_3 alkanes in terms of propane. Considering the stability and formation of vinyl chloride relative to the more common alkanes, it is estimated that less than 1 percent of all of the organics reported as C_3 alkanes are vinyl chloride. Based on this, vinyl chloride emissions are expected to amount to less than 0.027 TPY in Phase I and less than 0.16 TPY in Phase III.

5.2.6 Sulfuric Acid Mist

Sulfuric acid mist is a product that may be found in combustion flue gases. It is formed when SO_2 is oxidized to SO_3, followed by the combination of SO_3 with water vapor in the stack gas. Generally, enough water vapor exists in the stack to convert essentially all SO_3 to H_2SO_4 before it is emitted from the stack. As the H_2SO_4 is emitted and cooled below its acid dew point, it is transformed to a liquid aerosol known as "sulfuric acid mist."

To calculate emissions from fuel combustion, it is estimated that approximately 1 percent of the sulfur in the fuel could be transformed into SO_3. All SO_3 is assumed to convert to H_2SO_4. Total H_2SO_4 emissions are estimated to amount to 7.7 TPY in Phase I and 18 TPY in Phase III.

5.2.7 Hydrogen Sulfide

Hydrogen sulfide is a reduced sulfur compound whose odor can be detected at very low concentrations. The proposed facility will not intentionally emit any H_2S. Small quantities may be released as fugitive emissions from the gas treatment plant and as very small fractions of unoxidized sulfur in combustion flue gases.

Although very few data are available to quantify H_2S emissions, it is expected that less than 0.01 percent of the H_2S in the fuel gas will remain after combustion (Ref. 5-3). Hydrogen sulfide in the tail gas after incineration is also expected to be less than 0.01 percent of the total sulfur content. Phase I H_2S emissions are estimated to be less than 0.018 TPY. Phase III emissions will be less than 0.15 TPY.

5.2.8 Total Reduced Sulfur

As defined in the federal New Source Performance Standards (NSPS) for kraft pulp mills, total reduced sulfur (TRS) means the sum of the sulfur compounds hydrogen sulfide, methyl mercaptan, dimethyl sulfide, and dimethyl disulfide. TRS emissions from fuel oil combustion are expected to be negligible due to the very low sulfur content. Based on the total sulfur content of the fuel gas and the estimate that less than 0.01 percent of the sulfur is emitted in a reduced state, TRS emissions will not exceed 0.024 TPY in Phase I and 0.34 TPY in Phase III.

5.2.9 Reduced Sulfur

As defined in the NSPS for petroleum refineries, reduced sulfur means hydrogen sulfide, carbonyl sulfide, and carbon disulfide. Reduced sulfur

emissions from fuel oil combustion will be negligible due to the very low sulfur content of the fuel. Those from fuel gas combustion are not expected to exceed 0.01 percent of the sulfur in the fuel gas. Phase I emissions will be less than 0.03 TPY. Phase III emissions will not exceed 0.36 TPY.

5.3 *DE MINIMIS* EMISSION LEVELS

Emissions of certain pollutants from new sources are exempted from some or all PSD review requirements if the emission levels are *de minimis*. The *de minimis* values promulgated by EPA and the pollutants to which they apply are shown in Table 5-4. The projected emissions from the proposed facility are also shown in the table. Except for lead, all criteria pollutant emission rates are expected to exceed the *de minimis* values in Phase I. Insofar as the non-criteria pollutants are concerned, sulfuric acid mist

Table 5-4

DE MINIMIS VALUES AND PROJECT EMISSIONS

Pollutant	Emission Rate (TPY)			
	De Minimis	Phase I	Phase II	Phase III
Criterial Pollutants				
Carbon Monoxide	100	477	1,433	3,407
Nitrogen Oxides	40	1,236	4,097	7,366
Sulfur Dioxide	40	510	853	1,175
Total Suspended Particulates	25	285	782	1,515
Ozone (Volatile Organic Compounds)	40	190	761	1,477
Lead	0.6	0.06	0.25	0.46
Non-Criteria Pollutants				
Asbestos	0.007	nil	nil	nil
Beryllium	0.0004	nil	nil	nil
Mercury	0.1	nil	nil	nil
Fluorides	3	0.37	1.0	1.8
Sulfuric Acid Mist	7	7.7	13	18
Vinyl Chloride	1.0	0.027	0.089	0.16
Total Reduced Sulfur (including H_2S)	10	0.024	0.074	0.34
Reduced Sulfur (including H_2S)	10	0.028	0.103	0.36
Hydrogen Sulfide	10	0.018	0.055	0.15

emissions are estimated to slightly exceed the *de minimis* value beginning in Phase I. All other emissions of non-criteria pollutants are expected to be below the *de minimis* levels in all phases.

5.4 GEP STACK HEIGHT

In accordance with Section 123 of the Clean Air Act Amendments of 1977, EPA proposed regulations on stack heights in January 1979. Final regulations are expected to be promulgated in September 1981.

The primary purpose of the regulations is to prevent the use of excessively tall stacks as a means of controlling ground-level air pollution. Good engineering practice (GEP) stack height is defined as "the height necessary to ensure that emissions from the stack do not result in excessive concentrations of any air pollutant in the immediate vicinity of the source as a result of atmospheric downwash, eddies and wakes which may be created by the source itself, nearby structures, or nearby terrain obstacles." Thus GEP stack height identifies the minimum stack height at which significant aerodynamic effects are avoided as well as the maximum stack height allowable for modeling purposes. A stack height below GEP may be appropriate for small emission sources for which excessive concentrations would not result due to atmospheric downwash from the source structure or nearby structures. For relatively significant sources, the White River Shale Project proposes to apply GEP stack height.

Under the proposed regulations, GEP stack height is determined as follows:

$$H_G = H + 1.5\ L$$

where, H_G = good engineering practice stack height

H = height of the structure or nearby* structure

L = Lesser dimension (height or width) of the structure or nearby structure

*"Nearby" is defined as the distance equal to five times the height or width of the structure, whichever is less.

To avoid natural atmospheric effects which may cause excessive concentrations around very low sources, the proposed regulations recommend that a stack height of 30 meters be defined as good engineering practice, without demonstration for this height.

Figure 5-5 presents a process area plot plan showing the areas of aerodynamic downwash influence. The stack heights presented in Table 5-5 were determined based on the plot plan and the recommendations presented above. A discussion of the pertinent factors involved in the GEP stack height determinations is provided below.

Phase I. There are no nearby structures to influence the stack emissions of the hydrotreater reactor feed furnace or flare pilot; therefore, the stack heights were set at the recommended GEP stack height of 100 feet (30 meters) for these sources. Similarly, GEP stack height for the gas treatment plant is 100 feet and that value is used for modeling purposes. However, the actual stack height will be 200 feet. This is a safety factor to guard against excessive ground-level concentrations in the unlikely event the gas treatment plant malfunctions.

As discussed later, the Phase I boiler stacks will be 250 feet high to provide GEP stack height in Phases II and III. Phase I modeling is based on a GEP stack height of 100 feet.

The Union B retort recycle gas heater stack has as a nearby structure the Superior retort (197 feet diameter, 85 feet high); thus, GEP stack height is:

$$85 + 1.5\ (85) = 213 \text{ feet}$$

As shown in Table 5-4, the Union B stack height will be 200 feet.

The hydrogen plant reformer furnace for Phase I is a structure approximately 40 feet by 40 feet and 75 feet high. There are no other nearby structures to influence downwash; hence, GEP stack height is:

$$75 + 1.5\ (40) = 135 \text{ feet}$$

Table 5-5

SOURCE STACK HEIGHTS

Source	Stack Height (ft)	GEP Calculated Stack Height (ft)
Phase I		
Union B Retort Recycle Gas Heater	200	213
Hydrogen Plant Reformer Furnace	135	135
Hydrotreater Reactor Feed Furnace	100	100
Gas Treatment Plant	200[a]	100
Boiler (3 stacks)	250[a]	100
Flare	100	100
Phases II and III (in addition to Phase I above)		
Union B Retort Recycle Gas Heaters (1 stack each)	200	213-365
TOSCO II Retorts (2 stacks each, 4 total)	250	365
Hydrogen Plant Reformer Furnace (Phase II)	188	188
Hydrogen Plant Reformer Furnace (Phase III)	250	250
Hydrotreater Reactor Feed Furnace (Phase II)	100	100
Hydrotreater Reactor Feed Furnace (Phase III)	100	250
Gas Treatment Plants (2)	200[a]	100
Boilers (1 stack each, 2 total)	250	250
Flares (2)	100	100

(a) See discussion.

Phases II and III. Three more Union B retort cycle gas heaters will be added by Phase III. One of these will be in the downwash region of the Superior retort (GEP stack height = 213 feet, as before), while the other two will be within the range of influence of a TOSCO II retort, measuring approximately 50 feet by 90 feet and 230 feet high. For these two stacks, the GEP stack height is:

LEGEND:

PROCESS FACILITIES

1 COARSE SHALE RETORT: SUPERIOR
2 COARSE SHALE RETORT: UNION B
3 FINE SHALE RETORT: TOSCO
4 H_2 PLANT
5 HTU PLANT
6 PROCESS WASTEWATER TREATMENT
7 SULFUR PLANT

MINING AND MATERIAL HANDLING AND OTHER FACILITIES

A GATEHOUSE
B HAZARDOUS WASTE DISPOSAL SITE
C RAW SHALE STOCKPILE
D FINE SHALE STORAGE
E EXPLOSIVES STORAGE
F PARKING LOT
G MULTIPURPOSE BUILDING
H LABORATORY BUILDING
J WAREHOUSE
K FIREHOUSE
L CHANGE ROOM
M ADMINISTRATION BUILDING
N HELICOPTER PAD
O CAFETERIA
P MINE SERVICE BUILDING

UTILITIES

I BOILER AND POWER PLANT
II SUBSTATION
III COOLING TOWER
IV WASTEWATER TREATING (NON PROCESS)
V SEWAGE TREATMENT PLANT
VI RAW WATER TREATMENT PLANT
VII TRUCK LOADING
VIII SHALE OIL PUMP STATION
IX FLARE
Xa TANK: SHALE OIL PRODUCT
Xb TANK: BY-PRODUCT
Xc TANK: RAW SHALE OIL AND INTERMEDIATE PROCESS
Xd TANK: UTILITY
XI RUNOFF HOLDING POND
XII WASTEWATER HOLDING POND
XIII WATER RESERVOIR
XIV SULFUR STORAGE PAD

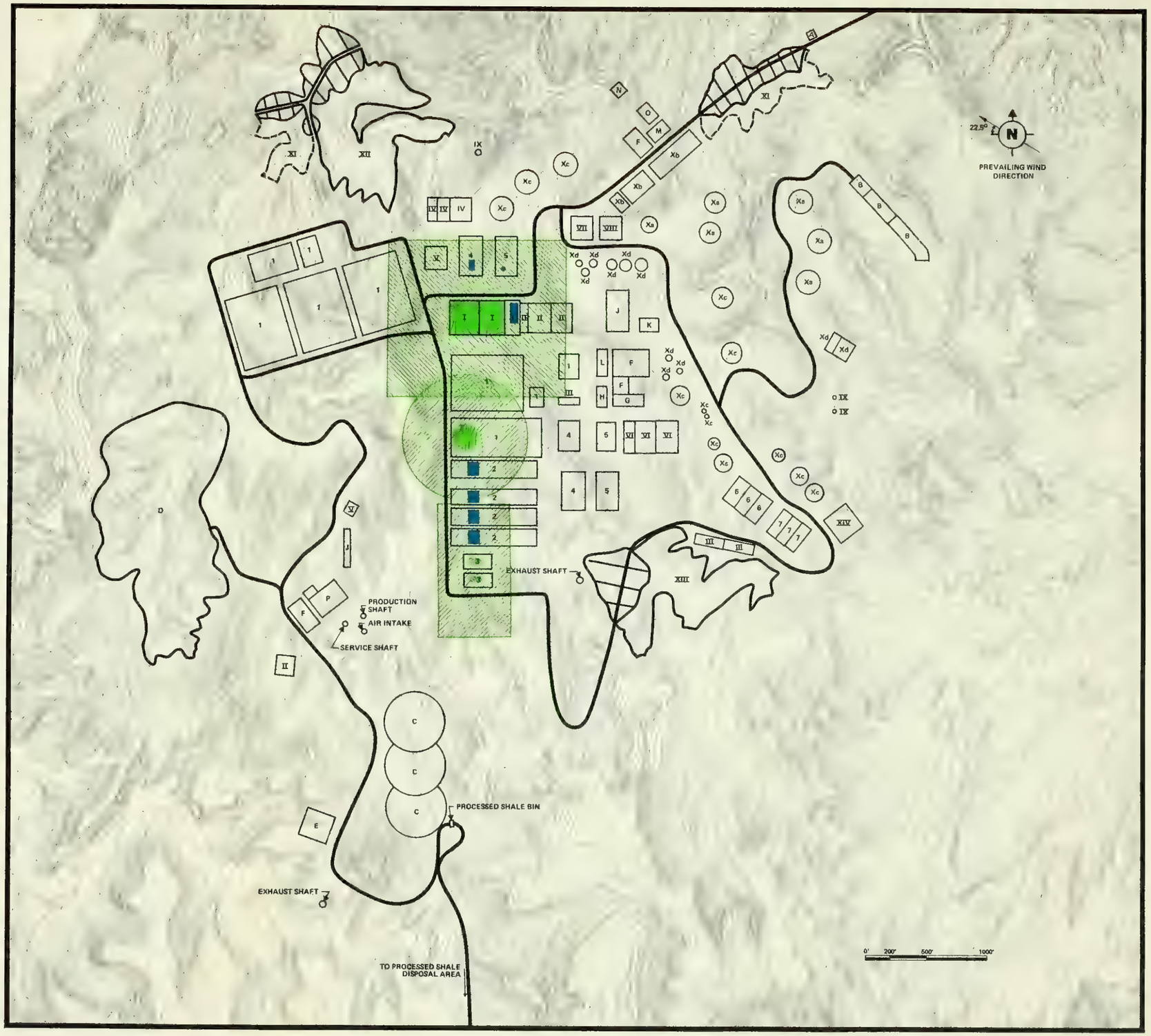


Figure 5-5 AREAS OF AERODYNAMIC DOWNWASH INFLUENCE

$$230 + 1.5\ (90) = 365 \text{ feet}$$

As in Phase I, actual stack height will be 200 feet due to the low emission rates. Higher stack heights are considered unnecessary due to the relatively low emission rates.

Two TOSCO retorts, parallel to each other on the 90-foot length, will be operating in Phase III. The exhaust stacks for each will be 250 feet above grade. Since they are nearby structures to each other, the GEP stack height is:

$$230 + 1.5\ (90) = 365 \text{ feet}$$

However, the predicted ground-level concentrations resulting from downwash calculations indicate that a stack shorter than GEP would be environmentally and economically appropriate due to the relatively low emission rates.

By Phase III, two more hydrogen plant reformer furnaces will have been added. Each one is approximately 40 feet by 90 feet and 75 feet high. There are no nearby structures to the furnace that will be built for Phase II, and the stack height will be equal to the GEP stack height of:

$$75 + 1.5\ (75) = 188 \text{ feet}$$

However, the furnace for Phase III will be near the Phase II and III boilerhouses (100 feet high) and its stack height will be equal to the GEP stack height of:

$$100 \text{ feet} + 1.5\ (100) = 250 \text{ feet}$$

The Phase III hydrotreater will also be near the Phase II and III boilerhouses, but its stack height will be 100 feet due to the relatively low emission rates.

As in Phase I, no nearby structures exist to influence emissions from the hydrotreater reactor feed furnaces, gas treatment plants, or flare pilots; hence, GEP stack height is 100 feet.

The boilerhouses for Phases II and III will be adjacent to each other, measuring a total of 300 feet by 500 feet and 100 feet high; thus, GEP stack height is:

$$100 + 1.5\ (100) = 250 \text{ feet}$$

GEP stack height for the Phase I boiler stacks after the Phase II plant is constructed is also 250 feet due to the influence of the Phase II structure. To allow for this, the Phase I boiler stacks will be built to a height of 250 feet but modeled at the Phase I GEP stack height of 100 feet in Phase I. For Phase II and III modeling, a GEP stack height of 250 feet is used.

5.5 BEST AVAILABLE CONTROL TECHNOLOGY

In conformance with EPA PSD regulations, a major new source must apply best available control technology (BACT) for each contaminant regulated under the 1977 Clean Air Act Amendments which the source emits in greater than *de minimis* quantities. As shown in Section 5.4, the WRSP will emit TSP, SO_2, NO_x, VOC, and CO in greater than *de minimis* amounts beginning in Phase I. Sulfuric acid mist emissions are estimated to equal the *de minimis* level beginning in Phase I. Therefore, BACT will be applied to all sources of TSP, SO_2, NO_x, VOC, CO, and sulfuric acid mist beginning in Phase I.

BACT is to be determined on a case-by-case basis, taking into account control efficiency, cost, environmental impact, and energy requirements. Alternative control techniques (when more than one technique is available) are presented for each emission source. BACT is discussed for each source and for each pollutant to which BACT is to be applied. The bases for the emission rates described below are given in Tables 5-1 through 5-3.

5.5.1 Construction

Particulate (dust) will be the only pollutant emitted in significant quantities from construction activities. Control practices during construction will consist of those measures set forth as BACT by the U.S. EPA Region VIII (Ref. 5-4). These include:

- Chemical dust suppression of all roads and disturbed areas
- Gravel parking lots
- Restriction of traffic to specified speeds and roads
- Paving of site access road and other frequently used roads
- Minimizing of land areas to be disturbed
- Watering of construction areas

5.5.2 Mining and In-Mine Crushing

The drilling, charging, blasting, loading, hauling, scaling, and roof bolting essential to room-and-pillar mining activities will generate airborne contaminants. Particulate (dusts) will be generated from all basic operations, and gaseous emissions will be generated from blasting and from operating diesel engines. In-mine crushing will reduce the shale to minus 4 inches. All air pollutants will be emitted from the mine exhaust shafts.

Particulate. Due to the large volume of air exhausted (2 MMscfm in Phase I and 11.25 MMscfm in Phase III), any particulate contained in the exhaust will be highly diluted. Because of the high air volume, it is considered technically and economically infeasible to control the mine vent exhausts by any means other than wet suppression and settling. Cyclones, wet dynamic scrubbers, venturi scrubbers, and bag filters are all too limited in capacity and have too large an inherent pressure drop to be used. Electrostatic precipitators can handle large volumes of air, but they have not been extensively tested on oil shale dust. Considering these factors, the proposed system consisting of wet suppression and settling is believed to provide BACT for the mine vent particulate.

The wet suppression of dust will include the following measures:

- Wetting the muckpile before and during truck-loading operations

- Watering haulageways to suppress traffic-generated dust
- Wet drilling on upper and lower benches and in roof bolting operations

The mine ventilation system will employ airstream velocities of about 150 to 250 ft/min. Due to the relatively low airstream velocities and the distances from the working face of the mine to the mine vent exhaust, it is estimated that more than 80 percent of the dust generated within the mine will settle out along the mine panels. This is based on testing conducted by Colony on underground mine dust (Ref. 5-5) and on data obtained by PEDCO at surface coal mines (Ref. 5-6). Colony determined that dust emissions from all mining operations including blasting would average about 0.018 lb/ton near the mine face and that about 80 percent could be expected to fall out before reaching the mine vent exhaust.

Phase I and Phase III emission rates due to basic mining operations are estimated to amount to 108 lb/day and 634 lb/day, respectively. This is equivalent to 0.018 lb/ton uncontrolled and 0.0036 lb/ton after control. There are no emission standards to use for a comparison, but this level of control is believed to compare favorably with other similar projects.

In addition to the particulate emanating from basic mining operations, in-mine crushing will contribute to the dust loading on the mine vent exhaust streams. In-mine crushing will be accomplished in two stages: a primary crusher will reduce the shale to minus 12 inches and a secondary crusher will further reduce the shale to minus 4 inches. Because only about one-half of the shale will be routed through the primary crusher and because the estimated uncontrolled dust emissions are relatively low, wet suppression and settling are believed to satisfy BACT requirements. Similar to the basic mining operations discussed above, 80 percent or more control is expected to be achieved. The estimated controlled emission rates for primary crushing are 60 lb/day in Phase I and 352 lb/day in Phase III.

Due to the greater generation of fines and the greater crusher rates, emissions from underground secondary crushing will be controlled by baghouses. Since the expected control efficiency of 99.7 percent (Ref. 5-1) is believed to provide the highest level of control achievable, this is assumed to satisfy BACT. Baghouse emissions from underground secondary crushing operations will amount to 19 lb/day in Phase I and 111 lb/day in Phase III. It is assumed that all particulate emitted from the baghouses remains suspended in the ventilation air and is carried out the mine vent exhaust. Crusher baghouses will be designed so that exhaust grain loadings will not exceed 0.018 gr/scf. For comparison purposes, the NSPS for iron and steel plants is 0.022 gr/scf and for coal preparation plants is 0.018 gr/scf. Additionally, BACT for other similar projects has been determined to be 99.7 percent control and 0.01 to 0.02 gr/scf.

Combustion particulate from fuel-burning mine equipment is expected to amount to 110 lb/day in Phase I and 660 lb/day in Phase III. The only reasonable way to control emissions is to routinely service mine equipment. All mine equipment will be maintained to obtain peak performance and to minimize emissions. Due to the small particle size, it is assumed that all combustion particulate remains suspended in the air and is exhausted from the mine vent exhaust.

Mine vent particulate emissions, totaling all sources, are shown in Table 5-6. As shown in the table, total mine vent particulate is expected to amount to 297 lb/day in Phase I and 1,757 lb/day in Phase III.

Gaseous Fumes. CO, NO_x, HC, and SO_2 will also be contained in the mine vent exhaust. The sources of these emissions are blasting and diesel-fueled equipment. Insofar as these two in-mine sources are concerned, BACT requirements are believed to be satisfied by minimizing blasting and

Table 5-6

MINE VENT PARTICULATE EMISSIONS

Activity	Phase I		Phase III	
	lb/day	t/yr	lb/day	t/yr
Mining	108	17.7	634	104
Primary Crushing	60	9.9	352	58
Secondary Crushing	19	3.0	111	18
Combustion	110	18.1	660	108
Total	297	48.7	1,757	288

by keeping engines adjusted for optimum performance in terms of minimum emissions.

If the blasting and fuel combusion emissions shown in Tables 5-1 to 5-3 are summed, the projected total emission rates for the mine vent exhaust are as shown in Table 5-7.

Sulfuric Acid Mist. Sulfuric acid mist emissions resulting from diesel fuel combusion will be negligible. Because of low cost-effectiveness and minimal environmental impact, no control is asserted to be BACT in this case.

Table 5-7

MINE VENT GASEOUS POLLUTANT EMISSIONS

Pollutant	Phase I		Phase III	
	lb/day	t/yr	lb/day	t/yr
NO_x	2,356	387	13,998	2,299
CO	846	139	4,823	792
HC	140	23	840	138
SO_2	155	26	930	153

5.5.3 Oil Shale Conveyors

Sources of particulate from conveying rock or other materials consist of windage along the belt and dust generated at conveyor feed points, conveyor transfer points, and conveyor discharge locations. Windage along the belt is normally controlled by enclosing the belt. All WRSP oil shale conveyors will be enclosed in accordance with U.S. Region VIII BACT guidelines (Ref. 5-4).

The conveyor belt itself and all conveyor feed, transfer, and discharge points will be enclosed. To further control dust, two basic methods are available. Dust can be suppressed using water sprays with chemical wetting agents, or it can be collected by venting and ducting the dust to a collection device. As a rule, wet suppression systems provide approximately 90 percent control, while dust collection systems can be designed to deliver up to 99 percent or more control.

After studying the costs, energy requirements, and environmental impacts of the two alternatives, a wet suppression system was found to be the best available control technology. The following descriptions and analyses support this selection.

Wet Suppression System. The wet suppression system for the control of particulate matter emissions uses a mixture of water with a chemical wetting agent. The mixture is normally about 1 to 2 gallons of chemical to 1,000 gallons of water, and about 3 to 5 gallons of mixture are used to treat a ton of material. The feed water is passed through a filter and then to a proportioner, which then delivers the dilute mixed solution on demand to the piping system. The mixture is applied by water jet to the dust sources specified. These sources generally are those where fractured dry material is loaded, discharged, or transferred.

The purpose of the wetting agent is to break down the surface tension of the water. This will allow the water to spread further, penetrate

deeper, and diffuse more widely than untreated water. The net result is to agglomerate the dust into larger particles that cannot become airborne. For applications in cold-weather climates, the entire water piping system can be winterized by electric tracing wires covered by thermal insulation.

Wet dust suppression systems are a well-developed, commercially available product to provide economical, efficient dust control. The systems are designed to control the dust at the application point areas; however, the carryover dust control effect resulting from treatment of the material at the application points will extend the dust control to subsequent material handling operations. Each system is designed for the specific ton-per-hour conveying capacity and the temperature, usually ambient, of the product.

The amount of the mixed solution applied to each ton of material is determined, not by the number of application points, but by the type, size, and temperature of the material. Increasing or decreasing the number of applications does not increase or decrease the amount of solution applied per ton.

Wet dust suppression systems are available commercially from a number of possible vendors. For such equipment systems, vendors supply the services of a field engineer to supervise the phasing of the system into operation and to instruct the operations personnel in the proper use and maintenance of the equipment. Experience has shown that to design and build a properly performing dust control system requires the services of such an experienced field engineer to adjust the system in accordance with the actual plant operating conditions.

In operation, wet suppression systems offer both advantages and disadvantages. The major advantages of the wet suppression system are:

- The dust is suppressed, not collected, and no dust disposal system is required.

- Capital, operating, and maintenance costs are less than for a dust collection system.

- The system is easy to operate.

The major disadvantages of the wet suppression system are:

- If the final product is very fine, too much spray can cause clogging or packing of the product.

- The installation of the spray nozzles and their relationship to the work requires considerable experience and sometimes painstaking adjustment before the application is successful.

- Control efficiencies are generally lower than those for dust collection systems.

Fabric Filter System. For particulate matter emission control, where very high collection efficiency is required or where very small particle size is encountered, a fabric filter system is commonly used. The filter bags are housed in a baghouse and the fabric filter system is sometimes called a baghouse system.

In a baghouse collection system, the dusty air is directed through ductwork by a suction fan to the baghouse where it is filtered by cloth tubes or bags. This system is analogous to a gigantic vacuum sweeper. The dust suspended in the air clings to the fabric while the cleaned air passes through. Many different kinds of bag materials (natural or synthetic yarns) and different weaves are available, depending on the application.

In the baghouse, the filter fabric is in the form of a long cylindrical tube closed at the top end. Many such tubes are supplied depending on the need. The tubes are supported vertically at the top, and air that is introduced through the open bottom must pass outward through the sides. Heavier dust particles are separated by gravity and drop directly into the hopper beneath the baghouse. The fines and light dust particles are carried in all directions by turbulent gas flow, depositing uniformly on the fabric.

Various methods are available to clean the accumulated dust from the filter bags. Such cleaning can be either intermittent or continuous. In intermittent cleaning, either the baghouse must be shut down, perhaps at the end of a shift, or spare baghouse circuits must be used. Continuous automatic cleaning systems are more expensive but can operate continuously and can handle high dust loadings. The dust adhering to the bag is shaken off or blown off by reverse air flow. It falls into a hopper below the baghouse and must be disposed of or utilized without creating a new pollution problem. The collected dust may be introduced back into the project flow process but this may create added dust problems downstream. If not reintroduced into the process, the dust must be trucked or slurried to a dump.

Major advantages of the fabric filter system are:

- The system is especially efficacious for control of very fine particle dust or where extra high efficiency collection is needed.
- If the collected dust has a separate market value, part of the cost of collection can be recovered.
- Collection of the dust can avoid possible clogging of fine-meshed screens.

Major disadvantages of the fabric filter system are:

- Disposal problems and additional costs are incurred if the collected dust has to be trucked or slurried away to a dump.
- It has higher capital, operating, and maintenance costs relative to dust suppression systems.

Phase I BACT. BACT considers economic impacts, energy impacts, and environmental impacts. Since the proposed wet suppression system is generally considered to have a lower control efficiency than the alternative dust collection system, a detailed analysis of the impacts is provided below in support of wet suppression as BACT for Phase I operations.

R. J. Evans (Ref. 5-7) has already made an economic comparison of the two dust control systems. His analysis, prepared in 1975, compared the capital and operating costs of a wet suppression system, fabric filter system, and a combination of the two for hypothetical hard rock stone crushing plants, operating at 300, 600, and 1,000 tons per hour. Evans's report of his analysis has been liberally used in this present analysis. Because of the high rate of inflation, present-day costs are much higher than Evans's 1975 figures, but the relative costs of the two systems are still valid.

In the WRSP Phase I development, typical process flow rates for the fines conveyors amount to 2,750 tons of shale per day, or about 115 tons per hour. Thus, the Evans analysis of costs at 300 tons per hour were used, as this was the lowest material flow rate studied.

The stone crushing plant described by Evans consisted of truck dump, hopper, seven main and transfer conveyors, a jaw crusher, two cone crushers, three sets of double-deck screens, six product bins, and discharge from the bins to trucks. Such a process and equipment arrangement bears a significant resemblance to the WRSP material handling requirements. For this reason, the results may be directly used in the BACT comparison of alternatives.

Fixed, working, and total capital costs for the wet suppression and the fabric filter systems are shown in Table 5-8. The costs for material and labor are detailed in Tables 5-9 and 5-10. For the wet suppression system, the major cost variables are the equipment and mechanical installation costs. For the fabric filter system, the baghouse and ductwork are the major items of expense. An analysis of the air requirements for the fabric filter system is given in Table 5-11. The fabric filter system is equipped with continuous automatic cleaning. Working capital was estimated for 60 operation days.

Table 5-8

CAPITAL COST COMPARISON BETWEEN WET SUPPRESSION AND FABRIC FILTER SYSTEMS FOR HARD ROCK CRUSHING PLANT[a,b]
(1975 Dollars)

Cost Item	Wet Suppression System	Fabric Filter System
Fixed Capital (depreciation, insurance, and tax base)	44,093	94,676
Working Capital (60 days operating cost)	5,036	11,210
Total	49,129	105,886

(a) Source: Reference 5-7.
(b) Capacity: 300 tons per hour.

No charges were made for interest during construction, field indirects, or contingencies since the capital costs include site erection and startup by the suppliers. It is assumed that the plant already has electric and water utilities. Financing was assumed by equity capital and depreciation over 20 years for both systems. The total investment including working capital was $49,129 for the wet suppression system and $105,886 for the fabric filter system.

It is assumed that the capital costs include engineering and fee. These costs are related to the system and capacity described, as typical for such installations for the time period when analyzed. For a plant today, the costs would vary somewhat depending on the physical plant layout, type of crushing equipment, number of pieces of crushing equipment, cost basis, escalation, etc. However, the cost ratio of the two systems shoud be about the same.

Table 5-9

CAPITAL COST SUMMARY FOR WET SUPPRESSION SYSTEM
FOR A HARD ROCK CRUSHING PLANT[a,b]
(1975 Dollars)

Cost Item[c,d]	Cost Per Year	
	Material	Labor
Wet Suppression Equipment	$13,219	$ —
Mechanical installation	923	11,844
Electrical installation	689	4,779
Water Filter and Flush	1,600	—
Mechanical installation	25	112
Electrical installation	20	190
High Pressure Truck Dump	2,495	—
Mechanical installation	111	798
Electrical installation	35	292
Shelter House	2,309	—
Mechanical installation	—	448
Electrical installation	21	175
Subtotal	21,447	18,638
Total material and labor	40,085	
Winterization (10 percent of cost)	4,008	
Total	44,093	

(a) Source: Reference 5-7.
(b) Capacity: 300 tons per hour.
(c) Mechanical installation labor at $14.00 per hour.
(d) Electrical installation labor at $14.57 per hour.

Table 5-10

CAPITAL COST SUMMARY FOR FABRIC FILTER SYSTEM
FOR A HARD ROCK CRUSHING PLANT[a,b,c]
(1975 Dollars)

Cost Item [d,e]	Cost Per Year	
	Material	Labor
Bag Filter No. 1	$10,413	$ —
Mechanical installation	3,432	1,162
Electrical installation	216	1,399
Duct work	1,430	1,274
Bag Filter No. 2	34,293	—
Mechanical installation	5,400	1,372
Electrical installation	256	1,119
Duct work	15,373	8,932
Subtotal	70,813	15,258
Total material and labor	86,071	
Dust Removal Equipment (10 percent of cost)	8,607	
Total	94,678	

(a) Source: Reference 5-7.
(b) Capacity: 300 tons per hour.
(c) Fabric filter system has continuous automatic cleaning with a maximum air-to-cloth ratio of 8:1.
(d) Mechanical installation labor at $14.00 per hour.
(e) Electrical installation labor at $14.57 per hour.

Table 5-11

AIR REQUIREMENTS FOR FABRIC FILTER SYSTEM
FOR A HARD ROCK CRUSHING PLANT[a,b]

Cost Item	cfm[c]	Capital Costs $/cfm (1975 Dollars)
Fabric Filter System		
Bag filter No. 1	6,000	3.54
Bag filter No. 2	42,000	1.75
Total	48,000	1.97

(a) Source: Reference 5-7.
(b) Capacity: 300 tons per hour.
(c) Cubic feet per minute.

For operating cost estimates, the only power requirement for the wet suppression system is 2 hp for the solution pump. The fabric filter system requires 2.3 hp for the screen conveyor, 23 hp for the compressor, and 115 hp for the fan, yielding a total of 140.3 hp.

Estimated annual operating costs for the wet suppression system are shown in Table 5-12, and for the fabric filter system in Table 5-13. For these tables, the data reported by Evans were adjusted. The original data were based on an operating time of 5 days per week, 8 hours per day, one shift, and 48 weeks per year. This yields 1,920 hours per year of operation. The WRSP will operate 8,000 hours per year, resulting in a significantly increased chemical wetting cost for the wet suppression system and horsepower electricity cost for the fabric filter system.

Another important adjustment affecting the wet suppression system was made. The Evans analysis assumed that the sprays would be used 40 percent of the time considering prevailing weather conditions. For the WRSP analysis, it

Table 5-12

OPERATING COSTS FOR WET SUPPRESSION SYSTEM
FOR HARD ROCK CRUSHING PLANT[a,b]
(1975 Dollars)

Cost Item	Cost Per Year
Direct Cost	
Electric power	
Motors, 140 1/3-hp (0.75 kWh/hr/hp x 8,000 hr/yr x 1.5 cents/kWh	$ 180
Maintenance	
Labor: 8 hr/week x 48 weeks x $6.50/hr	2,496
Material	2,000
Subtotal	4,496
Operation	
Labor: 3 hr/week x 48 weeks x $6.50/hr	936
Supplies	
Wetting agent: 300 tons/hr x 8,000 hr/yr x 0.0015 gal/ton x $2.60/gal	9,360
Payroll overhead (35 percent of labor)	1,201
Indirect Cost	
Office and general overhead (40 percent of maintenance and supplies)	5,542
Fixed Costs	
Taxes and insurance (2 percent of fixed capital)	882
Depreciation (5 percent of fixed capital)	2,205
Subtotal	3,087
Total operating costs	24,802
Total operating cost per ton of stone produced	.010

(a) Source: Reference 5-7, Revised.
(b) Capacity: 300 tons per hour.

Table 5-13

OPERATING COSTS FOR FABRIC FILTER SYSTEM
FOR HARD ROCK CRUSHING PLANT[a,b]
(1975 Dollars)

Cost Item	Cost Per Year
Direct Cost	
Electric power	
Motor, 2 hp (0.75 kWH/hr/hp x 8,000 hr/yr x 1.5 cents/kWh)	$12,630
Maintenance	
Labor: 12 hr/week x 48 weeks x $6.50/hr	3,744
Material	3,000
Subtotal	6,744
Operation	
Labor: 3 hr/week x 48 weeks x $6.50/hr	936
Supplies	
Bags: 490 bags/2 yr life x $8.60/bag	2,107
Labor: bag installation, 490 bags/2 yr bag life x 0.1 man-hr/bag x $6.50/man-hr	159
Subtotal	2,266
Payroll overhead (35 percent of labor)	1,694
Indirect Cost	
Office and general overhead (40 percent of maintenance and supplies)	3,604
Fixed Cost	
Taxes and insurance (2 percent of fixed capital)	1,894
Depreciation (5 percent of fixed capital)	4,734
Subtotal	6,628
Total operating cost	34,502
Total operating cost per ton of stone produced	.014

(a) Source: Reference 5-7, Revised.
(b) Capacity: 300 tons per hour.

was assumed the sprays would operate continuously, regardless of prevailing weather conditions. This also increased the estimated chemical costs significantly.

Other costs including labor and supplies were also increased. One item not adjusted was the estimate of replacement bag cost for the fabric filter system. This was previously assigned a 2-year replacement life, and it was felt that this would not be measurably reduced for round-the-clock operation. These adjustments were made to more closely reflect actual WRSP conditions and to determine the relative importance of the various items applied to these actual conditions.

The results in Tables 5-12 and 5-13 show that the total annual operating costs for the sprayers and baghouses are $24,802 and $34,502, respectively. In terms of cost per unit ton, the total operating costs are 1.0¢ per ton and 1.4¢ per ton, respectively.

Tables 5-12 and 5-13 also indicate that the annual energy consumption for the sprayers and baghouses are 12,000 kWh and 0.84 million kWh, respectively. This is equivalent to 0.005 kWh/t and 0.35 kWh/t, respectively.

Regarding skilled maintenance and operating labor components, the baghouse system will require more attention but not so much as to cause a significant effect on the plant personnel demand or on the regional labor supply. There will be enough water to operate the sprayers and sufficient electricity to operate the baghouses. The surfactant chemical for the wet suppression system will probably be shipped bulk by truck or railcar from Salt Lake City or Grand Junction, as will the replacement bags for the fabric filter system. In either case, the demand or delivery route is not expected to create a significant impact.

The environmental impact of wet dust suppression systems has also been considered. The intent of a Prevention of Significant Deterioration analysis is to demonstrate that the consumption of available increments is minimized (within economic limits) and that the ambient air quality is preserved so that the potential for future economic growth is maintained. Special PSD constraints are brought into consideration for Class I pristine areas.

The emission source for the wet suppression system is at or near the surface of the ground. The emitted material is diluted in the aerodynamic wake of the conveyor structure and further diluted by turbulence induced by thermal and mechanical effects and by wind speed and direction variability. In fabric filter systems, the same dilution mechanisms exist except that the emission is an ambient temperature jet plume at up to 100 feet above grade. The jet plume provides an initial dilution in place of the conveyor wake dilution for the wet suppression system. The dilution for either alternative will amount to roughly the same amount.

Significant dilution mechanisms that act on particulate emissions (in addition to turbulence, wind speed, and direction variability previously mentioned) include fallout due to gravity settling for larger particles and impact adsorption on ground surfaces of the smaller particles. Rainout can also reduce ground-level concentration, but at the WRSP site, precipitation is infrequent and rainout will probably not contribute a large measure of particulate air quality control.

Typically, an environmental impact study in a BACT analysis of atmospheric emissions controls would consider the air quality impact differences between the study alternatives. However, the amount of particulate matter emitted to the atmosphere by either of the two alternatives is small compared to total project emissions; thus, it is inappropriate to conduct a sophisticated air quality modeling effort.

The emissions inventory presented in Table 5-1 shows that for the wet suppression system emission sources (Nos. 6, 7, 8, 9, and 11), the total daily emission at 90 percent control amounts to about 70 pounds. Considering the cfm involved and the characteristics of bag collectors, it is estimated that this daily emission could be reduced to about 23 lb/day with a dust collection system. This represents approximately 97 percent overall control using baghouses designed to function at 99.7 control of inlet grain loading.

The 70 pounds per day is equivalent to 0.37 gram per second. If this is diluted by a factor of 1 million (a reasonable assumption) on its way to the site boundary, a ground-level concentration of 0.37 $\mu g/m^3$ would result. The fabric filter result would be even less, but it cannot be shown that either case produces a result of significant environmental impact.

Table 5-14 summarizes the comparison of wet suppression and fabric filter dust control systems. Regarding economic impacts, the table shows that the capital cost for wet suppression dust control is about one-half of that for dust collection using fabric filters. Annual operating costs for a wet suppression system are about 70 percent of the costs for operating a fabric dust collection system. It has previously been shown there are no potentially significant concerns associated with the economic impact analysis other than the costs.

Regarding energy impacts, fabric filters require significantly more energy than wet suppression systems (840,000 kWh/yr vs. 12,000 kWh/yr) and more energy input to the product (0.35 kWh/t vs. 0.005 kWh/t). No potentially significant concern has been found to offset the high energy requirement associated with the operation of baghouse dust collection systems.

Regarding environmental impacts, emissions from the WRSP Phase I conveyors are estimated to amount to about 70 lb/day at 90 percent control efficiency

Table 5-14

COMPARISON OF DUST CONTROL ALTERNATIVES
FOR HARD ROCK CRUSHING PLANT[a,b]
(Wet Suppression and Fabric Filters)

Cost Item	Control Alternative	
	Wet Suppression	Fabric Filter
Economic Impacts		
Capital Costs (1975)	49,129	105,886
Annual Operating Costs (1975)		
Dollars	24,802	34,502
¢/ton	1.0	1.4
Energy Impacts		
Total Energy, kWh/yr	12,000	840,000
Energy, kWh/t	0.005	0.35

(a) Source: Reference 5-7, Revised.
(b) Capacity: 300 tons per hour.

using wet suppression for control. For a baghouse dust collection system, emissions would amount to about 23 lb/day. Despite the lower control efficiency of the wet suppression system, neither alternative is expected to cause significant environmental impact.

In view of the foregoing analysis and summary results presented, it is proposed that wet suppression be designated as the BACT control strategy for Phase I emission source Nos. 6, 7, 8, 9, and 11 in Table 5-1.

Phase III BACT. The Phase III WRSP proposal also includes application of wet suppression dust control as shown on Table 5-3. In the preceding Phase I analysis, the results of the U.S. Bureau of Mines Report were drawn upon to support wet dust suppression as BACT for the certain intended applications. In Phase III, the application is generally the same as in Phase I, and similar conclusions can be made. Based on the Bureau of Mines study, the economics and energy requirements would be even more in favor of the wet suppression system in Phase III.

Insofar as environmental impact is concerned, the savings in cost and energy with a wet suppression system are believed to outweigh the limited environmental advantages of a baghouse dust collection system. As shown in Table 5-3, Phase III emissions from those sources controlled by wet suppression (source Nos. 4, 9-13, 15, and 17-19) amount to 634 lb/day (3.33 g/sec). This can be roughly translated into a 3 μ/gm^3 contribution to the TSP site boundary concentration, assuming a relative concentration factor of $1/10^{-6}$ as in Phase I. Using a baghouse dust collection system rather than wet suppression, it is estimated that Phase III emissions from the sources noted above could be reduced to about 200 lb/day. This could be expected to contribute 1 $\mu g/m^3$ to the site boundary TSP concentration. In comparing these results, WRSP has concluded that the economic and energy benefits realized from using a wet suppression system offset the relatively insignificant environmental advantages of a baghouse dust collection system.

5.5.4 Surge/Feed Bins and Storage Silos

Baghouses designed to operate at 99.7 percent control efficiency will minimize dust at all surge bins, feed bins, and storage silos. Outlet grain loadings will be maintained at less than 0.015 gr/scf. This is believed to provide the highest degree of control available and is in accordance with U.S. EPA Region VIII BACT guidelines (Ref. 5-4).

All surge/feed bin and silo baghouse emission points and emission rates are given in Table 5-15.

Table 5-15

RATES OF SURGE/FEED BIN AND SILO BAGHOUSE EMISSIONS

Source	lb/day	gr/scf
Phase I		
Mine conveyor surge bin	12.5	0.012
Storage silo feed	12.5	0.012
Union retort feed	2.1	0.010
Superior retort feed	16.9	0.010
Phase III		
Mine conveyor surge bin	37.0	0.012
Phase I and II storage silos (2)	12.5 ea	0.012
Phase III storage silo	25.0	0.012
TOSCO II retort feed (2)	9.5 ea	0.010
Union B retort feed (4)	2.1 ea	0.010
Superior retort feed silos (5)	10.4 ea	0.010
Superior retort feed bins (5)	6.6 ea	0.010

5.5.5 Surface Crushing and Screening

Particulate generated by surface crushing and screening operations will be contained by baghouses operating at 99.7 percent control efficiency. Outlet grain loadings will not exceed 0.021 gr/scf. This follows U.S. EPA Region VIII BACT guidelines (Ref. 5-4) and is equivalent to recent BACT determinations for other similar projects (Ref. 5-8 and 5-9). Estimated emission rates for Phases I and II are shown in Table 5-16.

Table 5-16

RATES OF PARTICULATE EMISSIONS FROM SURFACE CRUSHING AND SCREENING

Phase	Emission Rates		
	(gr/scf)	(lb/day)	(t/yr)
I	0.021	65	11
III	0.021	260	42

5.5.6 Raw Shale Stockpile

Routine emissions of particulate will result from the load-in, grooming, and wind erosion of coarse oil shale. Reclaim will be accomplished by an under-the-pile reclaim system whenever reclaim is required.

Phase I. Load-in to the storage pile will be achieved using a stacker conveyor. Dust control alternatives include:

- Water spray — 50 percent control (Ref. 5-10)
- Water spray with wetting agent — 75 to 90 percent control (Ref. 5-7, 5-11)
- Lowering well — 75 percent control (Ref. 5-11)

Since a lowering well is thought to be nearly as effective as wet suppression but less costly and avoids freezing problems, it is suggested that BACT be satisfied using the lowering well to control dust from load-in operations.

Dust generated by equipment used to groom the stockpile can be controlled only by minimizing vehicular traffic around the pile and by watering when vehicular activity is required. Vehicular traffic will be kept to a minimum through the use of a stacker for load-in and an under-the-pile tunnel system for reclaim. For the low level of scraper/loader traffic that may be required, watering will be practiced (when weather conditions permit) to control dust. This is the usual BACT strategy for such emissions.

During Phase I, 500,000 tons of coarse shale will be stockpiled for use when the mining operation is interrupted. It is estimated that approximately 65 percent of the raw shale stockpile will be dead storage. The best means available to control wind erosion and degradation of dead storage is to apply a chemical crusting agent. Ninety-five percent control of dust from the dead portion of the stockpile is expected to be achieved by sealing the sides of the pile (Ref. 5-11).

The remaining 35 percent of the 500,000 ton stockpile (175,000 tons) will consist of live storage. Techniques available to control wind erosion of live storage piles include:

- Watering — 50 percent control (Ref. 5-12)
- Enclosure — 95 to 99 percent control (Ref. 5-12)

Enclosure is estimated to cost about $110/ton (Refs. 5-11 and 5-12), or $19 million for a 175,000 ton enclosure. The installed cost for a watering system is expected to be far less expensive, costing about $15,000 (Ref. 5-11). This includes sprays, piping, pumping, and installation costs. Operating costs would be minimal.

Due to the high cost of enclosure and the non-hazardous nature of the dust, watering is proposed as BACT for wind erosion control of the live storage portion of the raw shale stockpile. Watering will be practiced when the potential for wind erosion is high and the possibility for freezing problems is remote.

Dust from reclaim operations will occur on a nonroutine basis. Alternative control strategies include:

- Water spray — 50 percent control (Ref. 5-12)
- Stacker/reclaimer — 25 to 50 percent control (Ref. 5-12)
- Under-pile reclaimer — 85 percent control (Ref. 5-11)

Of the methods avialable, the proposed under-the-pile reclaim system will provide the highest level of control; thus, BACT will be satisfied.

Phase III. By Phase III, the quantity of raw shale in live storage will remain at about 175,000 tons, but dead storage will increase to about 2.8 million tons. The Phase III BACT proposal is the same as that for Phase I:

- Stacker load-in and lowering well to control load-in emissions
- Watering to reduce dust generated by vehicular equipment
- Watering to control wind erosion of live storage
- Application of chemical crusting agent to control wind erosion of dead storage
- Reclaiming using an under-the-pile reclaim system

5.5.7 Fines Storage

During Phase I, fines will be stored for later use in Phase III. Sources of dust include load-in, grooming and compaction, wind erosion, and reclaim.

Load-in to the fines storage area will be accomplished using a movable stacker conveyor system. A wet dust suppression system providing approximately 90 percent control is believed to provide the highest level of control available; therefore, this meets BACT requirements.

After load-in, the fines will be groomed and compacted. Vehicle activity will be minimized by the use of the movable stacker conveyor system. Furthermore, watering will be practiced when weather conditions permit. Since these are the only reasonable means of controlling dust emissions from grooming and compacting operations, BACT requirements are expected to be satisfied.

Fines will be deposited for storage during Phase I in a small canyon, and only the top surface of the stockpile will be exposed. (The sides of the storage area will not be exposed.) Ultimately, the fines storage stockpile will cover a maximum of 30 acres; however, only 5 acres of the storage area will be exposed to the wind at any given time. The remainder will be sealed with an asphalt or latex sealant to prevent shale degradation and to eliminate wind erosion. For the active 5 acre area, there are basically only two alternatives to control dust:

- Watering — 50 percent control (Ref. 5-12)
- Compaction and application of dust suppressant — 85 percent control (Ref. 5-6)

During Phase I buildup of the stockpile, the fines will be compacted daily and a chemical dust suppressant will be applied to further reduce wind erosion. During Phase III reclaim, watering is believed to be the only reasonable means available to control wind erosion. Thus, BACT for wind erosion of the fines storage area will be achieved by: sealing filled areas, limiting unsealed areas to 5 acres or less in all phases, and compacting. Dust suppressants will be applied to unsealed areas in Phase I and they will be watered during Phase III when temperature allows.

During Phase III, the fines stockpile will slowly be reclaimed using front-end loaders. Under-the-pile reclaim is not practical or economical for the fines stockpile because of the small quantity being reclaimed and because it is basically a dead storage pile. The available control alternatives for product removal by front-end loaders are to minimize fall distance and to water the area to be reclaimed. Both of these control techniques will be employed during reclaim operations.

5.5.8 Processed Shale Conveyor

During Phase I, processed shale will be deposited onto the processed shale conveyor in a saturated condition (up to 20 percent moisture) and transported to the processed shale bin. From there, the processed shale will be loaded onto trucks and transported to the disposal area. During Phases II and III, the processed shale conveyor will be extended all the way to Southam Canyon, and the retorted shale will go directly to the disposal area.

Due to the high moisture content of the processed shale, dust emissions at conveyor feed points, transfer points, and discharge points are expected to be almost negligible. Based on the emission factor equation developed by Midwest Research Institute (Ref. 5-11), it is expected that the high moisture content of the processed shale (15 to 20 percent) will control dust by more than 99 percent.

Since water is applied to the processed shale primarily for cooling purposes, the cost for controlling dust by wetting is essentially nil. Because of this and because of the high level of control, baghouses or other control measures are considered to be unwarranted. For the processed shale conveyor, wetting is proposed as BACT.

5.5.9 Processed Shale Disposal

During Phase I, processed shale will be placed in a side canyon on the eastern ridge of Southam Canyon. Processed shale will be brought from the retorting area by conveyor south to the haul road. The conveyor will deliver the processed shale to a truck loading bin, and from there, trucks will move it along the haul road to the disposal area. Filling will advance with about a 25 percent slope on the advancing edge, with a ramp to permit the bottom-dump trucks to decend and ascend the slope, dumping the material in layers and compacting it with their wheels. Bulldozers will complete the shaping of the pile. At completion, the top surface of the pile will be at an elevation of 5,850 feet, with a 4:1 (horizontal:vertical) slope.

In Phase II, processed shale is collected from the retorts after cooling and transferred by conveyor to the disposal site in the eastern portion of Southam Canyon. A single conveyor with three transfer points and a tripper will carry processed shale to either of two movable conveyors each fitted with a tripper. Each movable conveyor, in turn, feeds a crawler-stacker that moves parallel to the conveyor and discharges processed shale in a linear pile. Bulldozers, scrapers, and compactors spread the pile and build up the disposal site in small increments to ultimate 50 foot lifts by working from the bottom up. Each of the two movable conveyors and its crawler-stacker will have sufficient capacity to handle the full design load. These movable conveyors will be relocated and extended during the operating phase, according to plan. Additionally, the approach conveyors will have to be sloped upward and/or raised to accommodate the greater height of the disposal pile during plant operation.

In Phase III, a second conveyor with its pair of movable conveyors and crawler-stackers will be extended into the central portion of Southam Canyon. This second conveyor will occupy the right-of-way of the Phase I processed shale conveyor. During Phase I, the potential sources of dust

emissions consist of load-in from bin to truck, road dust, dumping, grooming and compaction, and wind erosion. By Phase II, emissions related to the trucking operation will be eliminated by the extension of the processed shale conveyor. BACT for the conveyor is discussed above in Section 5.5.8. BACT for Phase I truck transport and grooming, compaction, and wind erosion in all phases is examined below.

Based on the initial moisture content of 20 percent and allowing for drying (to 15 percent), emissions from truck loading operations are expected to be relatively minimal. Using the emission factor equation of MRI (Ref.5-10), which accounts for moisture content, emissions from truck loading operations should not exceed 0.0003 lb/t at 15 percent water. The high moisture content of the processed shale will ensure that dust emissions are sufficiently well controlled at the truck loading station. This strategy is believed to provide BACT considering the high level of control that will be achieved by moisturizing the processed shale. The high cost in dollars expended per pound of dust controlled and the high energy use that would result from the utilization of alternative control techniques, such as enclosure with dust collection, is considered to be unwarranted.

The principal source of emissions from transporting the processed shale by truck to the storage area is road dust. Alternative techniques for controlling dust from haul roads include:

- Watering — 50 percent control (Ref. 5-11)
- Speed control — 25 to 80 percent control (Ref. 5-1)
- Chemical stabilization — 85 percent control (Ref. 5-4)
- Restriction of off-road use — up to 100 percent control (Ref. 5-4)

To control haul road dust, a combination of speed control, restriction of off-road use, and chemical stabilization will be practiced. Haul trucks

will be limited to a speed of 15 mph and will be required to minimize off-road travel. Moreover, the processed shale haul road will be chemically stabilized by working a dust suppressant into the road. In accordance with EPA Region VIII BACT guidelines (Ref. 5-4), the haul road will be stabilized using a chemical stabilizer such as Coherex at a dilution of 1:4 and at an application rate of 1 gal/yd^2 for the initial application. To maintain dust control, a chemical stabilizer will be re-applied once a month during those months that have less than 10 days with rainfall greater than 0.01 inch. This combination of road dust control measures is expected to provide 85 percent or more control and is in agreement with EPA Region VIII BACT policy.

After traveling the approximate haul distance of 1 mile or less, bottom-dump trucks will deposit their loads at the optimal location. Due to the high moisture content of the processed shale, dust emissions are not expected to exceed 0.0003 lb/t (Ref. 5-11). Since emissions are estimated to be relatively insignificant and since no reasonable means is available to further reduce dust, this is BACT.

Following dumping operations, bulldozers will shape and compact the pile. As the processed shale is spread and compacted, water will be sprayed on it when the dust potential is high and nonfreezing conditions exist. This is considered to be the only practical means of controlling dust; thus BACT requirements are fulfilled.

Alternative control measures for wind erosion include:

- Wind barriers — 30 percent control (Ref. 5-11)
- Watering — 50 percent control (Ref. 5-4)
- Chemical stabilizers — 85 percent control (Ref. 5-4)
- Revegetation — 75 percent control (Ref. 5-4)

To provide BACT, a combination of the above control measures will be employed. First, the processed shale storage area will be located in a canyon, thereby serving as a natural wind barrier while shielding the sides of the pile. Additionally, as the processed shale is placed in the fill area and compacted, chemical stabilizers will be sprayed on the pile to further reduce wind erosion.

The working areas of the processed shale pile will be limited to 30 acres in Phases I and III. Areas of the processed shale pile that are filled to final elevation will be contoured and plants will be placed in the depressions in earth-filled trenches, hence returning the land to a nearly natural level of wind erosion.

In summary, WRSP plans to take advantage of all opportunities to control fugitive dust emitted from processed shale disposal operations. The control measures described above are believed to provide the only reasonable solutions to dust control problems and are in agreement with common BACT practices.

5.5.10 High-Btu Gas Treatment Plant

High-Btu gas will be produced from the Union B retort in Phase I and from the Union B and TOSCO II retorts in Phases II and III. This gas will be used as fuel for selected process heaters and as feedstock for the hydrogen plant.

As produced by the retorts, the high-Btu gas contains ammonia and a variety of sulfur compounds. Combustion of the untreated high-Btu gas as fuel would likely produce SO_2 and NO_x emissions in excess of applicable standards.

Ammonia. In using retort off gas as fuel, ammonia in the gas can contribute significantly to NO_x emissions. The untreated retort off gas is expected to contain as much as 1 percent (vol) NH_3. To control NO_x

emissions resulting from the combustion of high-Btu gas, ammonia can be removed from the gas prior to combustion, or NO_x can be removed from the flue gases emitted by fuel-burning equipment. Since the latter method is not yet a commercially proven technology, removal of ammonia from the retort off gas is the only practical means of minimizing NO_x emissions.

Ammonia will be effectively removed from the high-Btu gas by water-washing. After washing, the NH_3 content is expected to be reduced to 10 ppmv. This represents approximately 99.9 percent removal of ammonia.

Sulfur. The untreated retort off gas is expected to contain 3 to 4 percent (vol) hydrogen sulfide and relatively small quantities of other sulfur compounds (e.g., mercaptans, carbonyl sulfide, carbon disulfide, etc.) as shown in Tables 4-5 and 4-7.

Two general approaches are available for controlling these SO_2 emissions. Sulfur can be removed from the gas as H_2S prior to combustion, or it can be removed from the flue gases as SO_2 after combustion.

Fuel gas treatment will remove 99 to 99.9 percent of the hydrogen sulfide. Non-H_2S sulfur compounds are generally unaffected by conventional gas treatment systems, reducing the overall sulfur removal to about 97 or 98 percent. In addition to providing an effective means of controlling SO_2 emissions, removal of sulfur from the fuel gas produces saleable quality sulfur.

Another important consideration in choosing one of the two approaches is associated with shale oil upgrading facilities. The upgrading step produces large quantities of hydrogen sulfide which must be recovered as sulfur via gas treating. Integration of the retort gas and upgrading gas treatment can provide a very cost-effective way to control SO_2.

The other general approach, flue gas desulfurization (FGD), is less effective than fuel gas treatment, being limited to between 90 and 95 percent. It also produces a useless sludge. Moreover, each process heater that uses the fuel gas would need an FGD system.

Fuel gas treatment was selected as the best approach to SO_2 control because it provides:

- Better emissions control
- Improved resource utilization
- Reduced chemical consumption
- Reduced waste disposal problems
- Greater flexibility
- A saleable by-product, sulfur

While a number of gas treating processes are available, experience has shown that only two are competitive and effective:

- Stretford Process. A liquid phase, catalytic oxidation process in which the gas stream is passed through a chemical solution for adsorption. The sulfur compounds are then converted to sulfur and precipitated from the solution.
- Amine/Claus/Tail-Gas Process. A gas phase process in which an amine solution is used to adsorb H_2S and CO_2 from the fuel gas. The H_2S and CO_2 are then released by amine regeneration. The regeneration gas is catalytically converted to sulfur in a Claus recovery plant, and tail-gas from the Claus plant is further treated in a tail-gas unit.

In the Stretford process, fuel gas H_2S concentration can be reduced as low as 10 ppmv. Concentrations of other non-H_2S sulfur compounds are essentially unaffected. Based on the data given in Table 4-5, total sulfur content of the Stretford treated high-Btu gas would be 0.40 gr/scf. This represents 99.96 percent H_2S removal and 98.0 percent overall sulfur control.

The amine/Claus/tail-gas system can be expected to reduce fuel gas H_2S to 0.10 gr/scf. Reduction of non-H_2S sulfur compounds cannot be predicted. After treatment, total sulfur content of the fuel gas could be expected to be a maximum of 0.49 gr/scf. This is equivalent to 99.5 percent H_2S removal and 97.5 percent overall sulfur control.

Estimated capital and operating costs for the Stretford and the amine/Claus/tail-gas systems are presented in Table 5-17. As shown in the table, the economics for the two processes investigated clearly favor the amine/Claus/tail-gas system. This is mainly due to the selection of a Claus/tail-gas system to treat the H_2S removed in the upgrading section of the facility. The additional Claus and tail-gas plant capacity required for treating the high-Btu gas is only incremental capacity over the amount needed for upgrading. In contrast, the Stretford costs reflect the need for a complete new system for each phase to process the incremental gas produced.

Table 5-17

ECONOMIC COMPARISON OF STRETFORD AND AMINE/CLAUS/TAIL-GAS PROCESSES FOR HIGH-Btu GAS [a]
(Millions of Dollars)

Cost/System	Phase I	Additional for Phase II[b]	Additional for Phase III
Capital Costs			
Stretford	11.1	19.3	–
Amine/Claus/Tail-Gas	4.7	10.0	–
Operating Costs, per year			
Stretford	0.48	1.9	0.45
Amine/Claus/Tail-Gas	0.25	1.0	0.23

(a) Capital cost expressed in first quarter 1981 dollars.
(b) Equipment added in Phase II will accommodate Phase III requirements.

Given that overall sulfur control is only slightly higher for the Stretford process (98.0 percent vs. 97.5 percent), the amine/Claus/tail-gas system was selected for treating the high-Btu fuel gas because its cost is about one-half of that for the Stretford system and because fewer operational difficulties are expected. The long operating success of the Claus plant and the demonstrated reliability of tail-gas processes make the system far preferable.

Tail Gas. Tail gas from the Claus plant will be processed in a tail-gas treatment plant to minimize atmospheric emissions of sulfur dioxide. Several processes are available to process the tail gas. The choice of which treatment process to use depends on many factors:

- Composition and volume of the tail gas
- Whether the system can be integrated as part of a new installation or whether it is an add-on to an existing Claus plant
- Initial investment cost and operating costs
- Utilities required, the sulfur product produced, and the wastes produced
- Performance, reliability, and operating range of the system

The Shell Claus off-gas treating (SCOT) process, the Beavon sulfur recovery process (BSRP), and the Wellman-Lord (W-L) process are the most widely applied processes. If the tail gas is low in CO_2, the SCOT process usually produces the best economics of the three. If the gas contains large amounts of CO_2, the W-L or the BSRP may be the best choice. All three processes can achieve the same approximate sulfur recovery efficiency.

The SCOT process was selected as the most suitable for the WRSP because it is expected to provide the most economical, reliable, and easily operable means of treating the Claus tail gas. In addition, the SCOT process produces no secondary wastes.

The SCOT process consists essentially of two components:

- A reduction stage in which all sulfur compounds and elemental sulfur in the tail-gas are reduced to H_2S
- An absorption stage in which H_2S is selectively removed by amine absorption/regeneration and is recycled to the Claus plant

Any H_2S remaining in gases discharged to the atmosphere is incinerated to SO_2.

The amine/Claus/SCOT gas treatment plant capacity will be increased in three phases. Emissions from the SCOT plant in Phases I, II and III are shown in Tables 5-1, 5-2, and 5-3. As indicated in the tables, minor amounts of pollutants other than sulfur dioxide will be emitted due to the combustion of small quantities of high-Btu gas.

The NSPS for petroleum refineries require that sulfur dioxide emissions not exceed 250 ppmv (at zero percent oxygen, dry). Sulfur dioxide emissions from the SCOT plant will not exceed this standard.

Relatively insignificant emissions of sulfuric acid mist will occur. If it is estimated that 1 percent of the SO_2 oxidizes to SO_3 (Ref. 5-1), Phase I emissions would amount to 1.7 lb/day and Phase III emissions would not exceed 14 lb/day.

5.5.11 Hydrotreater

A hydrotreater plant will be constructed in each of three project phases. High-Btu gas from the Union B and TOSCO II retorts will be used as fuel for the reactor feed furnace. In Phase I, the required heat input is 31 MMBtu/hr. At 806 Btu/scf, this will amount to 38,400 scf/hr. By Phase III full production, the heating value of fuel gas is expected to reach 887 Btu/scf due to addition of the TOSCO II retorts. Total heat input to the reactor feed furnaces in Phase III will amount to 150 MMBtu/hr (169,000 scf/hr).

Sulfur Dioxide. As discussed earlier, fuel gas treatment is proposed as BACT for all high-Btu fuel-gas-burning equipment. Fuel gas H_2S will be reduced to 0.1 gr/scf and total sulfur is not expected to exceed 0.49 gr/scf. This represents 97.5 percent SO_2 control for combustion of the Union B gas. Slightly higher control efficiency may be attained in Phases II and III based on a higher H_2S content of the untreated TOSCO II off gas.

Combining the heating values and the total sulfur content of the fuel gas results in an estimated emission rate of 0.17 lb/MMBtu in Phase I and 0.16 lb/MMBtu in Phase III. These compare favorably with utility and industrial boiler NSPS of 0.2 to 1.2 lb/MMBtu.

The BACT proposed for SO_2 from the hydrotreater reactor feed furnace is fuel gas treated to 0.10 gr-H_2S/scf.

Nitrogen Oxides. BACT for NO_x from high-Btu fuel gas combustion is discussed in connection with the gas treatment plant. As discussed, ammonia in the high-Btu gas will be reduced to 10 ppmv. After treatment, NO_x emissions are not expected to exceed the upper limit of the EPA range of NO_x emissions from the combustion of natural gas in small industrial boilers (230 lb/MMscf) (Ref. 5-1).

Using an emission factor of 230 lb/MMscf results in an emission rate of 0.28 lb/MMBtu. Although this is somewhat higher than the gas-fired boiler NSPS guideline of 0.2 lb/MMBtu, combustion modification or flue gas recirculation to reduce thermal NO_x is thought to be unwarranted due to the small size of the source (31 to 150 MMBtu/hr). In addition, it is believed that the emission estimate of 230 lb/MMscf is conservatively high, and actual emissions may prove to be lower.

Based on the above considerations, WRSP proposes fuel treatment to reduce ammonia to 10 ppmv as BACT for the hydrotreater reactor feed furnace.

Particulate. Particulate emissions from gas-fired heaters are relatively low due to the nature of the fuel. EPA suggests that emissions from natural gas combustion range from 5 to 15 lb/MMscf (Ref. 5-1). At 15 lb/MMscf, particulate emissions will not exceed 0.019 lb/MMBtu. If this is compared to the 0.03 lb/MMBtu NSPS for large utility boilers, it can be seen that BACT requirements are easily satisfied. In this case, the use of gas for fuel is proposed as BACT.

Carbon Monoxide and Hydrocarbons. CO and HC emissions will be limited by the usual BACT practice of optimizing excess air and allowing for sufficient mixing and residence time.

Sulfuric Acid Mist. H_2SO_4 emissions will be negligible due to the low sulfur content of the fuel and the low burn rate. Phase I emissions are estimated to amount to 1.3 lb/day, and Phase III emissions are not expected to exceed 8.1 lb/day.

5.5.12 Union Recycle Gas Heaters

During all phases of the project, Union B retorts will use shale oil and proportionally small amounts of high-Btu gas as fuel for the recycle gas heaters. In Phase I, total heat input to the Phase I Union B retort will amount to 240 MMBtu/hr. Shale oil will provide 211 MMBtu/hr and fuel gas will supply the remaining 29 MMBtu/hr. Based on heating values of 6.1 MMBtu/Bbl and 806 Btu/scf, Phase I burn rates will be 35 Bbl/hr oil and 36,000 scf/hr gas.

By the end of Phase II, three more Union B retorts will be constructed; this will make a total of four Union B retorts with a combined total heat input of 960 MMBtu/hr. During Phase III operations, oil will provide 928 MMBtu/hr (152 Bbl/hr) and fuel gas will furnish the remainder (32 MMBtu/hr).

Sulfur Dioxide. In using oil or gas as fuel, there are two basic methods of controlling sulfur dioxide emissions: either remove the sulfur from the

fuel prior to combustion, or remove the sulfur dioxide from the combustion flue gas. Using the latter method can provide up to 90 to 95 percent control; however, costs and energy requirements are high. In addition, exhaust temperatures are relatively low resulting in lower plume rise and higher ground level concentration.

As discussed in association with the high-Btu gas treatment plant, fuel gas sulfur can be reduced by 97 to 98 percent. In the case of shale oil, sulfur is removed in the upgrading process. More than 99 percent removal is expected to be achievable. Without flue gas desulfurization, exhaust temperature and plume rise are higher; thus, ground level concentration would be lower. In view of the control efficiencies, control costs, and environmental impacts associated with the two available control strategies, fuel treatment to remove sulfur is considered to be BACT.

In the upgrading process, the sulfur content of the shale oil will be reduced from approximately 7,000 ppmw to 20 ppmw. Sulfur in the upgraded shale oil will be less than a tenth of that in conventional fuel oils. As a result, sulfur dioxide emissions from combustion will be much lower than if conventional oil was burned.

Fuel gas hydrogen sulfide will be reduced to 0.10 gr/scf in the high-Btu gas treatment plant. Total sulfur content after treatment is expected to amount to 0.49 gr/scf, representing an overall sulfur removal efficiency of 97.5 percent.

As shown in Tables 5-1 and 5-2, sulfur dioxide emissions will amount to 5.5 lb/hr (0.023 lb/MMBtu) in Phase I and 6.9 lb/hr (0.007 lb/MMBtu) in Phase III. For comparison, the NSPS for power plants is 0.2 to 1.2 lb/MMBtu. Due to the low sulfur content of the fuel, SO_2 emissions will be much lower than the power plant NSPS. Consequently, BACT requirements are believed to be satisfied by burning low-sulfur upgraded shale oil (20 ppmw sulfur) and treated fuel gas (0.10 gr/scf H_2S).

Nitrogen Oxides. Generally speaking, three methods are available to control NO_x emissions from fuel combustion: combustion modification, fuel treatment, and flue gas cleaning. The latter method is still in the development stages and has not yet been commercially proven.

As one method of combustion modification, special staged burners which are capable of firing raw shale oil can be used to reduce NO_x emissions to less than 0.4 lb/MMBtu (Ref. 5-13). This represents approximately 20 to 45 percent control as compared to single-stage combustion. Other methods of combustion modification include limited excess air firing and flue gas recirculation. Up to 60 percent control may be achievable by employing one or more of these control techniques (Ref. 5-1).

In the raw shale oil upgrading process, fuel nitrogen content can be reduced from about 2.3 percent to 1500 ppmw. This reduction in the fuel nitrogen content can be expected to reduce emissions by approximately 75 percent based on the EPA fuel oil emission factor for NO_x (Ref. 5-1).

As described previously, the high-Btu gas treatment plant will reduce ammonia in the fuel gas to 10 ppmv. This will effectively minimize NO_x formation from fuel gas combustion.

On the basis of the foregoing discussion, the following measures are proposed as BACT:

- Limit shale oil nitrogen to 1500 ppmw
- Limit fuel gas ammonia to 10 ppmv
- Use low-NO_x burners

Using this combined control strategy, Phase I NO_x emissions will amount to 53.1 lb/hr, and Phase III emissions will not exceed 206 lb/hr. In terms of pounds per unit heat input, this is equivalent to 0.22 lb/MMBtu in Phase I and 0.21 lb/MMBtu in Phase III. As a comparison, the NSPS for a

shale-oil/fuel-gas fired power plant burning the same oil/gas fuel proportions as the recycle gas heaters would be 0.46 and 0.49 lb/MMBtu in Phases I and III, respectively. This shows that emissions will be controlled well within the limits of good practice.

Particulate. Particulate emissions can be controlled by cleaning the fuel and/or the flue gas. Proper combustion is also an important factor in controlling particulate emissions.

In firing oil and gas, cleansing of the flue gas particulate is usually not required to meet emission standards or BACT requirements. However, electrostatic precipitators may be employed to reduce particulate emissions from residual oils by 40 to 90 percent (Ref. 5-1).

In the process of upgrading the shale oil, nitrogen and sulfur concentrations are reduced. Although the upgrading processing is not designed to remove ash from the oil, the ash content of the upgraded oil is not expected to exceed 250 ppmw. This is comparable to a low ash No. 6 fuel oil and approaches that of conventional distillate fuel oil. Even though upgrading generally has little effect on the ash content, it is expected to provide for better atomization and cleaner combustion, resulting in relatively low particulate emissions.

Particulate emissions from fuel gas combustion are normally relatively low. Due to the small gas/oil fuel ratio, fuel gas will contribute very little to total particulate emissions.

Estimated particulate emission rates are 5.0 lb/hr in Phase I and 19.7 lb/hr in Phase III. Dividing these emission rates by their respective heat inputs results in a value of 0.021 lb/MMBtu. As a guideline, the NSPS for power plants is 0.03 lb/MMBtu. This demonstrates that the upgraded shale oil/treated fuel gas mixture can be burned at relatively low emission rates without resorting to expensive, energy consuming flue gas treatment systems. The proposed BACT for particulate is upgraded shale oil and treated gas as

fuel, with a restriction of 250 ppmw ash on the shale oil and a limitation on emissions of 0.021 lb/MMBtu.

Carbon Monoxide. Only relatively minor amounts of CO are expected to be generated from upgraded shale oil/treated fuel gas combustion. BACT for CO emissions is normally taken to be proper operation and routine maintenance. CO emissions are expected to amount to 8.0 lb/hr in Phase I and 32.5 lb/hr in Phase III.

Hydrocarbons. Only small amounts of HC are emitted from shale oil/fuel gas combustion in a well run plant. Emissions from the recycle gas heaters will not exceed 1.6 lb/hr in Phase I and 6.5 lb/hr in Phase III. As is commonly accepted, BACT will consist of proper operation and routine maintenance.

Sulfuric Acid Mist. If upgraded shale oil at 20 ppmw sulfur and treated fuel gas at 0.49 gr/scf are allowed as BACT for SO_2 emissions, H_2SO_4 emissions will be minimal. It is estimated that Phase I emissions will not exceed 1.8 lb/day and Phase III emissions will be less than 2.5 lb/day. Due to the low projected emissions, BACT requirements are expected to be met by limiting the fuel sulfur content.

5.5.13 Hydrogen Plant Reformer Furnaces

Hydrogen plant reformer furnaces will derive the required heat inputs from upgraded shale oil and proportionally small quantities of high-Btu gas. Phase I heat input will amount to 436 MMBtu/hr (420 MMBtu/hr oil, 16 MMBtu/hr gas). At full production, a total of 2,058 MMBtu/hr will be required for the Phase I, II, and III plants. BACT for the reformer furnaces is the same as that proposed for the Union B recycle gas heaters. As BACT for the reformer furnaces, WRSP proposes to:

- Limit the sulfur content of the upgraded shale oil fuel to 20 ppmw
- Limit fuel gas sulfur to 0.10 gr/scf hydrogen sulfide and 0.49 gr/scf total sulfur

- Limit oil fuel nitrogen content to 1,500 ppmw
- Limit fuel gas ammonia content to 10 ppmv
- Use low-NO_x burners
- Limit oil fuel ash content to 250 ppmw
- Minimize CO and HC emissions through proper operation and routine maintenance

Phase I sulfur dioxide, nitrogen oxides, and particulate emissions are expected to amount to 0.023, 0.22, and 0.020 lb/MMBtu, respectively. Phase III emissions will be equivalent to 0.008 lb/MMBtu SO_2, 0.22 lb/MMBtu NO_x, and 0.021 lb/MMBtu particulate.

Emissions of sulfuric acid mist will be minimal due to the low sulfur content of the fuel. In Phase I, estimated emissions are 2.3 lb/day. Phase III emissions will be less than 5 lb/day.

5.5.14 TOSCO II Ball Heaters and Lift Pipes

One TOSCO II retort will be constructed and operated in Phase II, and another in Phase III. By Phase III full production, 18,500 TPSD will be retorted in the two TOSCO II retorts. In the retorting process, ceramic balls will be heated using upgraded shale oil and high-Btu gas as fuel. Hot waste flue gas from the ball heaters contacts the raw shale in a series of lift pipes to preheat the shale. An incinerator is provided for control of HC emissions from the lift pipes. Before exhausting the flue gas used to preheat the raw shale, it passes through an incinerator, multiple cyclones, and a wet scrubber in series. Phase III emission estimates are given in Table 5-3.

Sulfur Dioxide. SO_2 will be emitted from the combustion of fuel in the ball heaters. As discussed previously in association with BACT for the Union recycle gas heaters, BACT for the combustion of upgraded shale oil

is believed to be provided by limiting the sulfur content of the oil fuel to 20 ppmw. BACT for fuel gas is discussed in connection with the high-Btu gas treatment plant. Fuel gas H_2S will be reduced to 0.1 gr/scf, making the total sulfur content 0.49 gr/scf.

Colony test data (Ref. 5-7) suggest that SO_2 emissions may be reduced 95 percent by contacting the flue gas with the raw shale, but no credit is taken for this due to the already low sulfur content of the fuel. By upgrading the shale oil and treating the fuel gas, SO_2 emissions will be limited to 0.02 lb/MMBtu and less than 5 ppmv. This is well below the 0.2 to 1.2 lb/MMBtu and 250 ppmv BACT guidelines applied by EPA in recent PSD New Source Reviews of oil shale facilities (Refs. 5-8 and 5-9).

Nitrogen Oxides. Fuel treatment is proposed as BACT for NO_x emissions from the ball heaters. Potential alternatives are discussed in connection with BACT for the Union recycle gas heaters and for the high-Btu gas treatment plant.

Upgraded shale oil fuel will be limited to 1,500 ppmw nitrogen and fuel gas will be limited to 10 ppmv ammonia. NO_x emissions from oil/gas fuel combustion are not expected to exceed 0.22 lb/MMBtu. As a guideline for BACT, the utility NSPS is 0.5 lb/MMBtu for shale oil fuel and 0.2 lb/MMBtu for gaseous fuel. Based on the TOSCO II gas/oil mixture, the utility NSPS would be 0.46 lb/MMBtu. Thus, BACT requirements are believed to be fulfilled using the proposed control strategy which will limit emissions to 0.22 lb/MMBtu.

Particulate. Particulate emissions from the TOSCO II ball heaters and preheat systems are due primarily to contacting the raw shale with the ball heater combustion gases in the lift pipes. Particulate emissions consist mostly of raw shale and condensible hydrocarbons.

Due to the heavy grain loading and the large exhaust volume, the only practical means to control particulate emissions is to use multiple cyclones and a wet scrubber in series. Multiple cyclones can be expected to reduce particulate emissions by 93.8 percent (Ref. 5-1).

To fulfill the wet scrubber requirement, a high-energy venturi scrubber is proposed. Of the wet scrubbers available, venturi scrubbers provide the highest level of control achievable. At a 30-inch pressure drop across the venturi, 99.5 percent control and outlet grain loadings of 0.02 gr/scf are expected to be obtained. While a higher pressure drop could provide higher control efficiency, the excessive economic and energy impacts are thought to outweigh the increase in control efficiency.

Total Phase III emissions from both TOSCO II retorts are estimated to amount to a total of 45 lb/hr with an attendant outlet grain loading of 0.02 gr/scf. This compares favorably with the material handling NSPS for smelters and iron/steel plants, 0.022 gr/dscf, which is used as a BACT guideline.

Based on the above analysis, BACT requirements are believed to be satisfied by maintaining an outlet grain loading of 0.02 gr/scf. It is proposed that this be accomplished using multiple cyclones at 93.8 percent control efficiency and a venturi scrubber at 30-inch pressure drop and 99.5 percent control efficiency. Overall control efficiency would be 99.7 percent.

Hydrocarbons. Hydrocarbons are taken up by the ball heater combustion gas in the lift pipes. Incineration is the only viable means to control this source. To reduce HC emissions, the TOSCO II retort design includes an incinerator which reduces overall HC emissions by 85 percent (Ref. 5-16). Exhaust concentrations are expected to be near 92 $ppmw_C$ (as carbon) based on the Colony test data.

In lieu of applicable emission standards, the guidance limit for Lurgi coal gasification plants is used as a BACT guideline. This value is 100 $ppmw_c$. At 92 $ppmw_c$, lift pipe emissions are believed to be within acceptable limits.

As BACT for lift pipe hydrocarbons, WRSP proposes to reduce potential emissions by at least 85 percent, limiting HC emissions to 92 $ppmw_c$. Daily and yearly emission rates are given in Table 5-3.

Carbon Monoxide. CO emissions from combustion processes are normally controlled by ensuring complete combustion is achieved. CO emissions are expected to be minimal due to complete combustion and incineration of the flue gas at temperatures greater than 1,200F and at 0.05 seconds residence time. This is the accepted BACT practice.

Sulfuric Acid Mist. H_2SO_4 emissions will be negligible. Low-sulfur fuel is expected to provide BACT. Phase III emissions are estimated to amount to 3.9 lb/day.

5.5.15 TOSCO II Elutriators

The TOSCO II elutriator separates processed shale from the ceramic heat transfer balls. If feasible, a portion of the boiler plant flue gas may be diverted through the elutriator to preheat the balls before they enter the ball elevator.

Due to exhaust volume, the emission stream characteristics, the location of the elutriator, and the physical size of particulate control equipment, the only practical means to reduce elutriator particulate emissions to acceptable levels is to use cyclones and a wet scrubber in series. Based on performance data published by the U.S. EPA (Ref. 5-1), multiple cyclones can be expected to reduce the particulate content of the exhaust gas by at least 93.8 percent. Control efficiencies for wet scrubbers vary depending on the type and the operating specifications.

The most efficient wet scrubber available is a high-energy venturi scrubber. Depending on the pressure drop across the venturi, overall control efficiencies as high as 99.8 percent can be achieved; however, significant power costs are incurred when operating the venturi scrubber at ultra-high control efficiencies because of the high pressure drop required. Incremental operating costs per unit pound of particulate collected become exceedingly high at pressure drops above 30 inches.

As BACT for the TOSCO II elutriators, multiple cyclones are proposed at 93.8 percent control efficiency in series with a high-energy venturi scrubber at 99.5 percent control and 30-inch pressure drop. Based on the above control efficiencies and the estimate that 1 percent of the raw shale feed is the load to the cyclones, the estimated emissions are as shown in Table 5-18.

As shown in Table 5-3, the exhaust from each elutriator scrubber will be combined with the exhaust from the TOSCO II shale moisturizer and emitted from a single stack.

Although there are no NSPS that specifically pertain to the elutriators, performance standards for material handling processes in other kinds of

Table 5-18

PARTICULATE EMISSIONS FROM TOSCO II ELUTRIATORS

Item	Phase II Retort	Phase III Retort	Phase III Total
Emission rate, lb/hr	2.4	2.4	4.8
Exhaust volume, scfm	26,500	26,500	53,000
Grain loading, gr/scf	0.01	0.01	—

industries can be used as a measure of BACT. The NSPS for dust collectors at iron and steel plants is 0.022 gr/dscf. As shown in Table 5-18, outlet grain loading from the elutriator venturi scrubbers will be well below this guideline value.

5.5.16 TOSCO II Processed Shale Moisturizers

Processed shale is cooled and wetted by contact with sour water. Using a wet scrubber to cleanse particulate from the steam given off is the only dependable method to control emissions because of the high moisture content. Of the wet scrubbers available for this application, a high-energy venturi scrubber will provide the highest level of control.

The proposed BACT for the TOSCO II shale moisturizers consists of a venturi scrubber operated at 30-inch pressure drop and 99.5 percent control efficiency. This will provide the optimum level of control in terms of cost, energy, and environmental impact. Using an estimated inlet grain loading of 4 gr/scf, Phases II and III emission estimates are as shown in Table 5-19.

Emissions from the shale moisturizers will be combined with the elutriator exhaust and emitted from a single stack on each retort.

Table 5-19

PARTICULATE EMISSIONS FROM TOSCO II
PROCESSED SHALE MOISTURIZERS

Item	Phase II Retort	Phase III Retort	Phase III Total
Emission rate, lb/hr	4.3	4.3	8.6
Exhaust volume, scfm	25,000	25,000	50,000
Grain loading, gr/scf	0.02	0.02	—

As a guideline for BACT, the NSPS for material handling at iron and steel plants, 0.022 gr/dscf, can be compared to the scrubber outlet grain loading. As shown in Table 5-19, outlet grain loadings are below the guideline value.

5.5.17 Boiler and Power Plant

The boiler plants will use low-Btu off gases from the Superior retorts as the primary fuel, plus upgraded shale oil as supplemental fuel to stabilize the combustion of the low-Btu gas. In Phase I, the total heat input to the boiler plant will amount to 283 MMBtu/hr of which 255 MMBtu/hr will be derived from low-Btu fuel gas. At 70 Btu/scf, 3.6 MMscf/hr of fuel gas will be required. The remaining 28 MMBtu/hr will be obtained from upgraded shale oil at a burn rate of 4.6 Bbl/hr.

By the time full plant capacity is reached in Phase III, the total heat input will amount to 2,195 MMBtu/hr from low-Btu fuel gas and 243 MMBtu/hr from upgraded shale oil. Total burn rates will be 31.3 MMscf/hr fuel gas plus 39.9 Bbl/hr upgraded shale oil.

Sulfur Dioxide. The two basic control alternatives for SO_2 consist of either removing the sulfur from the fuel prior to combustion or removing SO_2 from the flue gases. Depending on the species of sulfur present in the fuel gas, removal of the sulfur from the fuel can generally achieve higher control efficiencies than FGD at lower costs.

The sulfur in the Superior low-Btu gas is present as a mixture of compounds. As part of the product quench system, the Superior retort design incorporates a water-wash step which reduces the total sulfur content to 175 ppmw. Sulfur removed from the gas leaves the retort in the form of sulfates and sulfites dissolved in the retort waters. Based on the estimated sulfate and sulfite concentrations in the retort water and the expected sulfur content of the retort off gas, a sulfur removal efficiency of 96.1 percent is calculated to be achieved by the retort scrubber.

To further reduce the sulfur content of the low-Btu off gas, it may be possible to apply Stretford technology; however, the cost per unit of sulfur removed would be exceedingly high, due to the already low (175 ppmw) sulfur content of the scrubbed gas. In addition, the Stretford effectiveness cannot be accurately estimated because the chemical forms of the sulfur in the Superior off gas are not well known.

The contribution to SO_2 emissions from supplemental upgraded shale oil will be very small, due to the low sulfur concentration in the oil. As described earlier, more than 99 percent of the sulfur in the shale oil will be removed during upgrading. The upgraded shale oil will have a maximum sulfur content of 20 ppmw.

The combustion of low-Btu gas at 175 ppmw sulfur and upgraded shale oil at 20 ppmw sulfur would result in a total emission rate of 96.7 lb/hr in Phase I, 281 lb/hr in Phase II, and 835 lb/hr in Phase III. This is equivalent to 0.34 lb/MMBtu in all phases. Although it is expected that NSPS for electric utility steam generating units will not be applicable (since no power will be sold), it is likely the NSPS for industrial boilers will be revised to resemble the more stringent utility standards. Therefore, the utility NSPS is used as a guide to measure BACT. For solid-derived fuel, the utility NSPS allows a maximum of 1.2 lb/MMBtu and requires a 90 percent reduction in potential emissions. If emissions are less than 0.6 lb/MMBtu, 70 percent control is required. The proposed emissions are well within these limitations.

As a further check on BACT, the sulfur content of the fuel gas can be compared to the refinery NSPS for fuel gas. This standard requires that the H_2S content in fuel gas be limited to 0.1 gr/dscf. If it is assumed that all of the 175 ppmw sulfur in the scrubbed gas occurs as H_2S, the maximum H_2S content of the low-Btu gas would be 0.10 gr/scf. This is a conservative assumption since other sulfur species, such as COS, CS_2, R-SH, and SO_x, will probably account for some of the sulfur content.

BACT proposed for the boiler plant consists of limiting the sulfur content in the low-Btu gas to 175 ppmw by the Superior scrubber, and limiting the sulfur content of the supplemental fuel to 20 ppmw by upgrading the shale oil. While this control strategy is believed to provide BACT, modeling indicates that PSD SO_2 increments could be exceeded at Phase II and III capacity. Because of this, WRSP proposes to go beyond BACT requirements and further reduce SO_2 emissions from low-Btu gas combustion by 80 percent in Phases II and III. Since it is expected that the sulfur species in the fuel gas will consist primarily of non-H_2S compounds, Stretford fuel gas treatment would not be suitable. Consequently, FGD is the only means available to reduce emissions.

Due to the relatively efficient removal of sulfur compounds in the Superior scrubber and the large volume of gases involved, SO_2 concentrations before FGD processing are estimated to be very low. Inlet concentrations will likely be in the 50 to 100 ppmv range. On the basis of 80 percent reduction by the FGD system, outlet concentrations will approach 10 to 20 ppmv. In terms of pounds of SO_2 per million Btu, SO_2 emissions from the boiler plants would amount to 0.068 lb/MMBtu. This is believed to exceed even the stringent of BACT requirements.

Nitrogen Oxides. In burning low-Btu gas, three methods are available to control NO_x emissions: removal of ammonia from the gas prior to combustion, combustion modification, and flue gas removal. The latter method is not yet commercially available in the U.S.

Very little data are available for NO_x emissions from the combustion of low-Btu gas. As shown in Table 4-3, a large fraction of the Superior off gas will be molecular nitrogen. Insofar as NO_x formation is concerned, the ammonia content of the gas may be of greatest interest, since NH_3 readily forms NO_x at high flame temperatures. At low enough flame temperatures, NH_3 tends to favor combustion to N_2 and H_2O rather than NO_x.

In the Superior retorting process, off gases are water-washed before leaving the retort. After scrubbing, the ammonia content is expected to be reduced to 10 ppmv. This represents approximately 99.5 percent removal of NH_3.

In large gas-fired boilers, combustion modification can be an effective means of controlling NO_x emissions. The methods available and their associated control efficiencies include (Ref. 5-1):

- Staged combustion: 30 to 70 percent
- Low excess air firing: 10 to 30 percent
- Flue gas recirculation: 20 to 60 percent

Thermal NO_x from firing the low-Btu gas is expected to be very low. This is because the high molecular nitrogen content of the gas is expected to be equivalent to very effective flue gas recirculation. The slow mixing and combustion of low-Btu gas will result in relatively low maximum flame temperatures.

The NO_x contribution from the supplemental upgraded shale oil is expected to be small. As described earlier, upgraded shale oil will be limited to a nitrogen content of 1,500 ppmw.

Although very little data are available with which to quantify NO_x emissions from low-Btu gas combustion, emissions are not expected to exceed the gas-fired power plant NSPS of 0.2 lb/MMBtu, which is based on control using combustion modification. Preliminary data found in the draft of the "Pollution Control Guidance Document for Oil Shale, Volume II," indicate that NO_x emissions from burning low-Btu gas that has been scrubbed of NH_3 may be as low as 0.06 lb/MMBtu. However, the emission estimates given below are based on 0.2 lb/MMBtu because of the uncertainty in NO_x emissions from the combustion of low-Btu gas and as a measure of conservatism in the air quality modeling. Estimated total NO_x emissions by phase are:

- Phase I: 56.6 lb/hr
- Phase II: 164 lb/hr
- Phase III: 487 lb/hr

Table 5-20 compares NO_x emissions from the proposed facility and pertinent emissions standards. As shown in the table, NO_x emissions will not exceed the industrial and utility boiler standards for gaseous fuel, and they will be lower than NSPS for gas/oil mixtures.

The proposed BACT for NO_x emissions from the boiler plants consists of limiting NH_3 in the fuel gas to 10 ppmv, limiting the nitrogen content in the supplemental fuel (upgraded shale oil) to 1,500 ppmw, and limiting emissions to 0.2 lb/MMBtu.

Table 5-20

COMPARISON OF BOILER PLANT
NO_x EMISSIONS AND EMISSION STANDARDS

Plant Emissions/Standards	lb/MMBtu
Boiler Plant Emissions	0.20
NSPS Standards	
Industrial Boiler	
— Gaseous fossil fuel	0.20
— Liquid fossil fuel	0.30
— Gaseous and liquid fuel mixture (9:1)	0.25
— Solid fossil fuel	0.70
Utility Boiler	
— Gaseous fossil fuel	0.20
— Shale oil fuel	0.50
— Gaseous and shale oil fuel mixture (9:1)	0.23
— Solid fossil fuel	0.50

Particulate. Particulate matter from combustion processes consists of solid particles and liquid droplets in the flue gas. These are generally either ash from the fuel and carbonaceous material (soot) resulting from incomplete combustion. Liquid droplets may consist of unburned fuel droplets and sulfuric acid mist.

Normally, flue gas treatment for particulate emissions from oil and gas-burning equipment is not required because of the low ash content of the fuel, the low uncontrolled particulate emissions, and the high cost per pound of particulate that would be removed from the flue gas if control equipment were installed. As shown in Tables 5-1, 5-2, and 5-3, particulate emissions from the boiler are not expected to exceed 0.03/MMBtu without flue gas cleaning equipment. Presently, the NSPS for industrial boilers is 0.10 lb/MMBtu; however, this standard may soon be revised to a more restrictive level, such as the utility NSPS of 0.03 lb/MMBtu. In any case, WRSP boiler plant emissions are not expected to exceed the more stringent utility standard.

As BACT for boiler plant particulate emissions, WRSP proposes to limit the ash content of the supplemental fuel (upgraded shale oil) to 250 ppmw, to comply with good combustion practices, and to limit emissions to 0.03 lb/MBtu.

Carbon Monoxide and Hydrocarbons. The only practical means of controlling carbon monoxide and hydrocarbon emissions from the boiler plant is to ensure that the boiler is designed and operated in a manner that minimizes unburned combustibles. Estimated emission rates are given in Tables 5-1, 5-2, and 5-3. BACT for carbon monoxide and hydrocarbon emissions from the boilers will consist of proper design, operation, and maintenance to ensure that boiler plants function at sufficient excess air levels.

Sulfuric Acid Mist. H_2SO_4 emissions from the boiler plant and other facilities are expected to be slightly greater than the *de minimis* level in Phase I and exceed the *de minimis* level in Phase II. It is possible to control sulfuric acid emissions using SO_2 wet scrubbers equipped with high efficiency mist

eliminators or electrostatic precipitators (ESP) at low operating temperatures. But both of these control methods are considered impractical and unwarranted for the WRSP boilers in Phase I. During Phases II and III, FGD and high efficiency mist eliminators will minimize sulfuric acid mist emissions.

In Phase I, it is likely that approximately 1 percent of the sulfur in the fuel will oxidize to SO_3, combine with water vapor to form H_2SO_4, and condense in the atmosphere. EPA has ruled in other recent PSD New Sources Reviews that any SO_3 emissions should be considered sulfuric acid mist (Ref. 5-15). In Phases II and III, potential H_2SO_4 emissions will be reduced by 80 percent through the use of FGD and mist eliminators.

Assuming 1 percent of the sulfur in the fuel oxidizes to SO_3 and all SO_3 is converted to H_2SO_4 mist, boiler plant emissions will amount to 5.8 TPY in Phase I. During Phases II and III, H_2SO_4 emissions will not exceed 3.4 TPY and 10.1 TPY, respectively.

The proposed Phase I BACT for boiler plant H_2SO_4 mist is to limit fuel gas sulfur content to 175 ppmw and upgraded oil sulfur content to 20 ppmw. FGD will further reduce potential H_2SO_4 emissions in Phases II and III.

5.5.18 Storage Tanks

Hydrocarbons will be emitted from the storage tanks shown in Table 5-21. As indicated, several of the WRSP storage tanks will be heated. These include the raw shale oil tanks, upgraded shale oil tanks, recovered oil tanks, and fuel oil tanks.

The type of tank used to store petroleum liquids depends upon the volatility of the liquid being stored. Based on the storage temperatures and the vapor pressures of the shale oils and fuel oils that will be stored, floating roof tanks are considered to be the most appropriate means of storage. Double-seal floating roof tanks that are designed, constructed, and maintained in accordance with 40 CFR 60, Subpart Ka, will be used for storing

Table 5-21

PETROLUEM TANKAGE SUMMARY

Tank	Phase	Capacity[a]	No. of Tanks	Diameter (ft)	Height (ft)	Roof Type	Heated
Union B Raw Shale Oil	I	115	1	134	46	Floating	Yes
Superior Raw Shale Oil	I	125	1	150	40	Floating	Yes
Combined Raw Shale Oil	II	420	2	180	47	Floating	Yes
Combined Raw Shale Oil	III	750	3	200	45	Floating	Yes
Upgraded Product Oil	I	120	1	134	48	Floating	Yes
Upgraded Product Oil	II	405	2	180	45	Floating	Yes
Upgraded Product Oil	III	725	3	200	45	Floating	Yes
Recovered Oil (Slop)	I	5	1	30	40	Floating	Yes
Recovered Oil (Slop)	II	10	1	43	40	Floating	Yes
Recovered Oil (Slop)	III	10	1	43	40	Floating	Yes
Diesel Fuel	I	17.5	1	58	38	Cone	No
Diesel Fuel	II	22.5	1	60	45	Cone	No
Diesel Fuel	III	27	1	70	40	Cone	No
Fuel Oil (No. 5)	I	13	1	48	40	Cone	Yes
Fuel Oil (No. 5)	II	55	1	100	40	Cone	Yes
Fuel Oil (No. 5)	III	98	1	134	40	Cone	Yes
Naphtha	I	60	1	100	44	Floating	No

(a) Capacity in 1000 barrels. Capacities shown are the capacities added in each phase.

all volatile petroleum products. Due to the low vapor pressures, diesel oil and No. 5 fuel oil will be stored in fixed roof tanks. These are standard BACT practices.

5.5.19 Flares

The proposed retorting and upgrading facility will include three flares, one added in each phase, for use during upset conditions. During normal operations, a small amount of cleaned high-Btu gas will be burned continuously to provide a pilot flame.

Because of the extreme turndown requirements, flares are normally nozzle mix burners. Steam jets are frequently used to promote good mixing and provide an adequate flow of combustion air. Alternatively, the air can be supplied by fans, possibly at lower operating cost and with less noise.

To satisfy BACT requirements, WRSP proposes to fit all flares with steam injection systems designed to ensure smokeless combustion over the operating range of the flare. This is in accordance with good engineering practice and with recent BACT determinations for other similar projects (Refs. 5-8 and 5-14).

Routine flare pilot emissions are shown in Tables 5-1, 5-2, and 5-3.

5.5.20 Valves, Flanges, and Pump Seals

If uncontrolled, fugitive HC emissions from valves, flanges, and pump seals could amount to as much as 50 lb/1000 Bbl production (Ref. 5-1). A routine program consisting of good housekeeping and maintenance is expected to provide a BACT control efficiency of 50 percent.

5.6 NORMAL NONSTEADY STATE CONDITIONS

This section discusses operational conditions which are expected to result in nonsteady state emissions over the course of a normal operating year.

5.6.1 Guard Bed Reactor Catalyst Change

The guard bed reactor catalyst operates sacrificially. The arsenic and other heavy metals removed in the guard bed deposit on the catalyst. As the heavy metal deposition builds up, the catalyst loses activity and the bed plugs up. Guard bed catalyst is nominally expected to require change out on a monthly (30-day) basis.

During guard bed catalyst change out, nonstandard emissions will occur in two ways:

- Reactor steam out may release small quantities of hydrocarbon gases to the atmosphere. This effect will be minimized by operating procedures.
- Spent catalyst discharge will generate dust which can contain significant quantities of arsenic. This will be controlled by enclosing the discharge hopper and the receiving truck and purging the enclosure with purge air discharge via a wet scrubber.

Since spare guard bed reactors are provided, there is no loss of arsenic removal capacity during catalyst changes.

5.6.2 Hydrotreater Catalyst Replacement

Hydrotreater catalyst will require replacement on what initially is expected to be a 9- to 12-year schedule. No increase in emissions in any other part of the plant will result when one hydrotreater reactor is out of service. Reactor shutdown, cleanout, and catalyst change are standard operations in the petroleum refinery industry. Well-established procedures will be used to minimize potential emissions due to leakage.

5.6.3 Claus Plant Catalyst Replacement

Claus sulfur plant catalyst will require replacement on a 2- to 4-year schedule. This is a standard procedure in the gas-treating industry and well-established procedures are available to limit the potential for emissions.

The major impact of Claus plant shutdown is that the hydrogen sulfide removal capability of the retort gas treating system will be reduced and the hydrogen sulfide content of the plant fuel gas will increase proportionately. This effect is minimized by providing excess Claus plant capacity.

In Phase I where the nature of the development operation may result in more frequent Claus plant shutdowns, 100 percent duplication of the design Claus plant requirements is provided so that there will be no loss in hydrogen sulfide control capability. In Phases II and III, the actual increase in hydrogen sulfide content of the fuel gas will depend upon the size of Claus plant that is shutdown, the number of retorts in operation at the time, and the actual hydrogen sulfide content of the retort gas. Phase I operations will guide the Claus plant design for Phases II and III to achieve desired control efficiencies during shutdowns.

5.6.4 Retort Turnaround

Initially, it is expected that each retort will be shutdown up to 35 days per year for maintenance and overhaul. Operationally, this will reduce the particulate, ammonia, and hydrogen sulfide loads in the plant emissions control systems.

The shutdown itself will result in temporary, but short-lived, increases in particulate and hydrocarbon emissions from the retort being turned around. These emissions will arise almost entirely from cleaning the retort to render it safe for maintenance crews.

REFERENCES — SECTION 5

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5-2 Trace Elements Associated with Oil Shale and Its Processing, U.S. Environmental Protection Agency, Region VIII, EPA-908/4-78-003, May 1977.

5-3 Health Impacts, Emissions, and Emission Factors for Noncriteria Pollutants Subject to De Minimis Guidelines and Emitted from Stationary Conventional Combustion Processes, prepared for U.S. Environmental Protection Agency by TRW Environmental Engineering Division, Redondo Beach, CA, EPA-450/2-80-074, June 1980.

5-4 "Compilation of Past Practices and Interpretations by EPA on the Air Quality Review of Surface Mining Operations," U.S. Environmental Protection Agency, Region VIII, December 1979.

5-5 P. W. Marshall, "Mine Dust and Fumes Control," Colony Development Operation, 1974.

5-6 Survey of Fugitive Dust from Coal Mines, U.S. Environmental Protection Agency, Region VIII, EPA-908/1-78-003, February 1978.

5-7 R. Evans, Methods and Costs of Dust Control in Stone Crushing Operations, Bureau of Mines Information Circulat 8669, U.S. Department of Interior, 1975.

5-8 "Prevention of Significant Deterioration of Air Quality Conditional Permit to Commence Construction and Operation, Colony Development Operation," U.S. Environmental Protection Agency, Region VIII, July 1979.

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5-11 R. Bohn, T. Cuscino, Jr., and C. Cowherd, Jr., Fugitive Emissions from Integrated Iron and Steel Plants, Midwest Research Institute, Kansas City, Missouri, EPA-600/2-78-050, March 1978.

5-12 Technical Guidance for Control of Industrial Process Fugitive Particulate Emissions, prepared for U.S. Environmental Protection Agency by PEDCO Environmental Inc., Cincinnati, Ohio, EPA-450/3-77-010, March 1977.

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5-14 Compilation of BACT/LAER Determinations, U.S. Environmental Protection Agency, EPA-450/2-80-070, May 1980.

5-15 U.S. Environmental Protection Agency, Region IX, Technical Review of PSD Permit Application for Harry Allen Power Station, January 1981.

5-16 "Lift Pipe Hydrocarbon Emissions," Addendum No. 1, Colony PSD Application.

6. AIR RESOURCES MONITORING

Section 6

AIR RESOURCES MONITORING RESULTS

6.1 MONITORING PROGRAMS

AeroVironment Inc. (AV) has been measuring air quality and meteorology on the Ua-Ub tracts for over 6 years. The original baseline measurements were taken during 1975 and 1976 when 12 sites were recording data. Baseline data are summarized in the Final Environmental Baseline Report (Ref. 6-1). For the interim program, four meteorological monitoring sites operated during 1977, 1978, 1979, and 1980, with one site (A6) continuing to monitor air quality as well as meteorolgy. Site A6 has been the main site during this program for monitoring representative general conditions in the vicinity of the proposed activity. These data have been summarized in yearly reports prepared by the White River Shale Project (Ref. 6-2). This monitoring program is ongoing and is expected to enter a new phase late in 1981 when construction is begun. Additional sites and measurements will be added as needed to monitor the air quality impacts of construction and operation of the proposed facility.

6.1.1 Existing Program

The air quality on Tracts Ua and Ub has been monitored continuously since baseline data collection began. Initially the measurement effort was extensive, because no previous data on air quality or meteorology had been collected in the area. As knowledge of baseline pollutant levels was obtained and their general lack of spatial variation was demonstrated, the number of monitoring stations was reduced during the second year of monitoring. The objectives of these baseline measurements were twofold:

- To characterize the air quality environment near the tracts in sufficient detail to provide a complete description of the baseline situation, against which future air quality could be compared

- To describe the meteorological environment near the tracts in sufficient detail to provide input data for simulation modeling of the dispersion of air pollutants that might be generated by future developments on the tracts

During subsequent years, monitoring of air quality has continued at one site and meteorological measurements have continued at four sites. This additional monitoring has provided continuity to the baseline data base and helped satisfy a third objective:

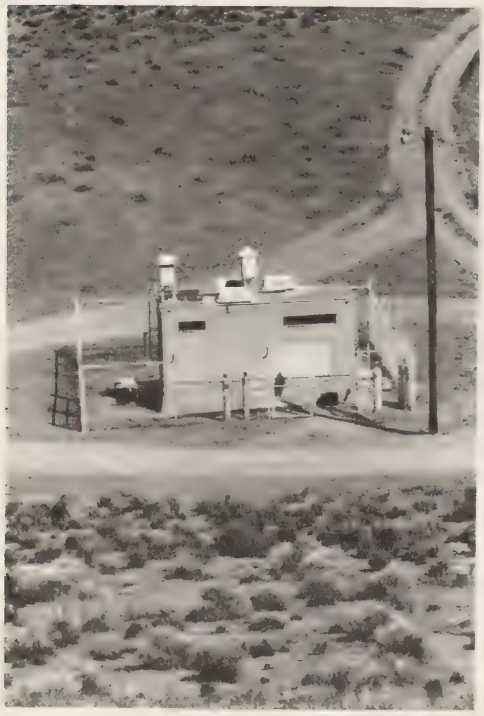
- To determine the year-to-year variation of the baseline air quality and meteorology of the area, in order to see whether the more intensive baseline measurements adequately represented a climatological baseline

The air quality parameters monitored during the baseline and interim programs are particulates (TSP), sulfur dioxide (SO_2), and hydrogen sulfide (H_2S). These were measured at eight sites during the first year of monitoring, at four during the second year, and at one for the remaining time. Ozone (O_3), hydrocarbons (HC) and carbon monoxide (CO) were measured at three of these sites during 1975 and then reduced to one (Site A6) for the other 5 years. Because concentrations for most of these pollutants were generally very low and fairly uniform over the tracts, these deletions do not affect the validity of the data base. The gaseous pollutant monitoring equipment was installed inside trailers, such as the one shown in Figure 6-1. This trailer was located at Site A6, and a high-volume TSP sampler is mounted on a platform on top. Figure 6-2 shows the locations of all air quality and meteorological sites in the tract area.

Meteorological parameters were also monitored extensively throughout the tracts during the initial years. These measurements included rawinsonde soundings and mixing height as well as the more basic meteorological parameters. During the interim period, these measurements were reduced to include only one meteorological tower and three other secondary sites. Meteorological parameters presently monitored at the main site, Site A6,

NORTH

EAST



SOUTH

WEST

Figure 6-1 SITE A6 MONITORING TRAILER AS VIEWED FROM NORTH, EAST, SOUTH AND WEST

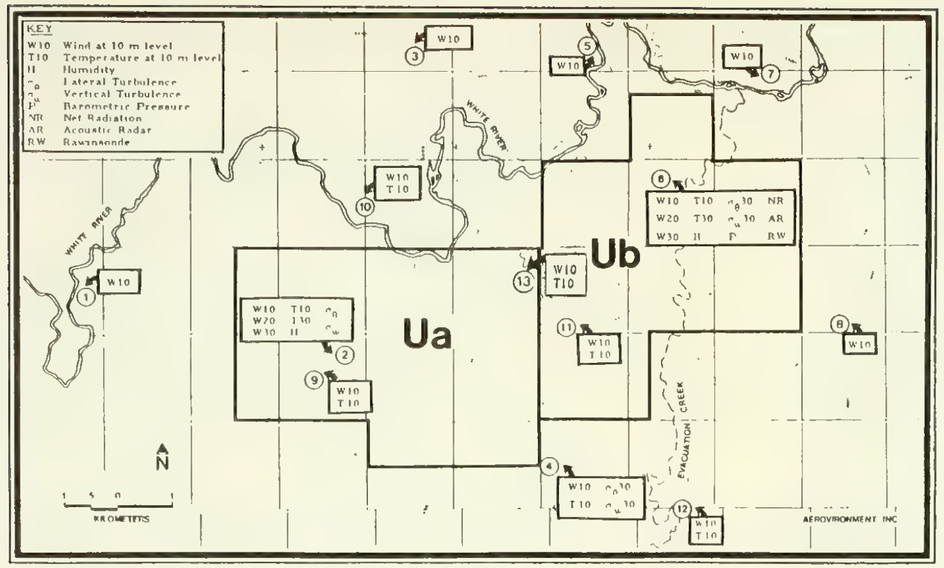
are wind speed, wind direction and its variance, ambient temperature, delta temperature, dew point, barometric pressure, and net thermal radiation. Temperature is measured at two levels (10 and 30 m) and wind data are measured at three levels (10, 20, and 30 m) at this site. Sites A4, A11, and A13 are also used to measure wind speed, wind direction, and temperature. Wind variance is also measured at Site A4 at the 10-meter level.

Visibility was measured during the first year of the program by both a nephelometer at Site A2 and photographs at Site A9.

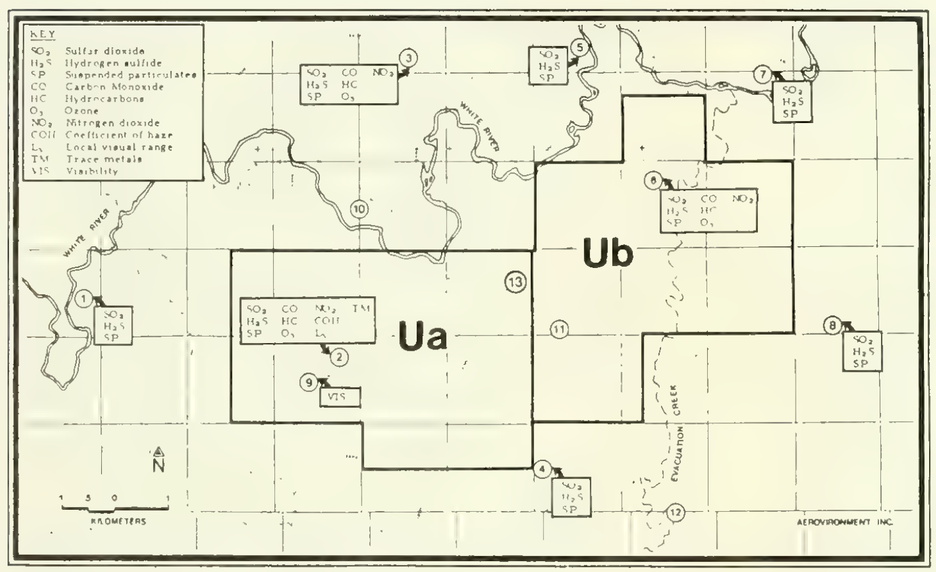
The meteorological and air quality program on Ua and Ub was set up before PSD guidelines (Ref. 6-3) were established. Monitoring instruments have been converted to conform to the requirements of these guidelines. Because frequent audits and calibrations were performed throughout the project as part of the quality assurance program, data obtained prior to PSD conversion should be fully acceptable for PSD purposes.

During the interim program quality assurance has been provided through four techniques:

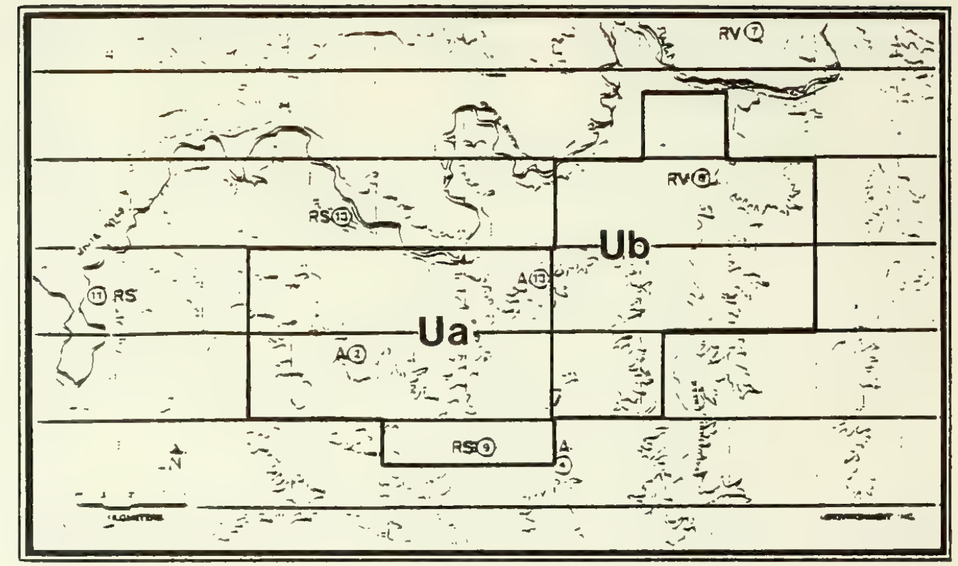
- All the instruments used were audited four times during the year.
- The air quality equipment was recalibrated monthly (dynamic multiple point).
- The equipment was span and zero checked every 2 days.
- The White River Shale Project was participating voluntarily in an air pollution measurement quality assurance program implemented by the U.S. Environment Protection Agency in addition to the normal internal quality assurance procedures maintained by AV (an in-depth description of the quality assurance program is contained in the report "Quality Assurance Plan for Air Resources Monitoring, Oil Shale Lease Tracts Ua-Ub") (Ref. 6-4).



a. METEOROLOGY



b. AIR QUALITY



c. PRECIPITATION

Note: Sites currently operating are A4, A6, A11 and A13.
Sites A4, A11 and A13 measure meteorological parameters only.

Figure 6-2 MEASUREMENT STATIONS ON TRACTS Ua AND Ub

Table 6-1 lists the air quality and meteorological instruments used and the parameters measured during the interim program. Several changes were made in 1980 to reflect current PSD guidelines.

A cup anemometer continuously measures wind speed. The rotational speed of the cup is linearly related to the electronic output on the chart recorder. Wind direction is measured with a wind vane consisting of an asymmetrically shaped object mounted at its center of gravity about a vertical axis. The vane is connected to a potentiometer, which produces a linear signal representing wind direction. Sigma theta is measured by calculating the root-mean-square value of the wind direction input signal, computed over a selected signal frequency range.

Temperature is measured by a linear thermistor composite network providing a linear variable resistance that is converted to a signal suitable for data logging. The thermistor is mounted in a radiation shield to avoid errors from ambient radiation. Delta temperatures are computed by taking the difference in temperatures at the 30- and 10-meter levels of the meteorological tower.

Humidity is measured by a hygrograph which utilizes a human hair bundle and is recorded on a chart mounted on a clock drive drum.

A miniature net radiometer measures net radiation. The radiometer is a temperature-compensated device with hemispherically shaped polyethylene windshields. The model used in the WRSP network provides a continuous record of net radiation.

Precipitation is measured using a standard, 6-inch recording and continuous-recording (cammed to punch at 5-minute intervals) weighing gauges.

Ozone is measured by gas phase ethylene-ozone chemiluminescence. Chemiluminescence is the emission of light from substances undergoing a chemical

Table 6-1

AIR QUALITY AND METEOROLOGICAL MONITORING EQUIPMENT (1977-1980)

Parameter	Instrument	Location
Suspended Particulates (TSP)	General Metal Works Model 5000 and Sierra Instruments Model GMWC-200H hi-vol	A6 (co-located hi-vol installed 1/80)
Sulfur Dioxide (SO_2) Hydrogen Sulfide (H_2S) Total Sulfur (TS)	Tracor Model 270 HA sulfur analyzer, gas chromatography Thermo Electron Corp. Model 43 pulsed fluorescent SO_2 analyzer	A6 (discontinued 2/80) (Installed 2/80, only measures SO_2)
Nitrogen Oxides (NO, NO_x)	Monitor Labs Model 8440E NO/NO_x analyzer, chemiluminescence	A6
Hydrocarbons (THC, CH_4)	Beckman Instruments Model 6800 gas chromatograph, flame ionization	A6 (discontinued 5/80)
Carbon Monoxide (CO)	Beckman Instruments Model 6800 gas chromatograph, flame ionization Monitor Labs Model 8310 infrared	A6 (discontinued 5/80) (Installed 6/80)
Oxidants (O_3)	Monitor Labs Model 8410E ozone analyzer, chemiluminescence	A6
Wind Speed and Wind Direction	Meteorology Research Inc. Model 1022 anemometer	A6, (10, 20, and 30 m) A4 (10 m)
Wind Speed, Direction, and Temperature	Meteorology Research Inc. Model 1071 mechanical weather station	A11 (10 m) A13 (10 m)
Wind Variance	Meteorology Research Inc., R.M. Young anemometer, and AeroVironment Inc. sigma meter	A6 (30 m) A4 (10 m)
Temperature	Meteorology Research Inc. thermistors with R.M. Young shield	A6 (10 and 30 m) A4 (10 m)
Relative Humidity	WeatherMeasure Inc. Model H321S hygrograph	A6
Barometric Pressure	Science Associates Model 370 aneroid barometer with electrical readout	A6
Net Thermal Radiation	Fritschen net radiometer	A6
Precipitation	Fischer & Porter automatic gauges	A2, A13, RS9
	Standard 6-inch diameter storage gauges	A2, A4, A13, RS9, RS11, RS13, RV7, RV8

reaction. Ozone anlyzers use the gas phase reaction of ozone with ethylene to produce such an emission, which is detected by a sensitive photomultiplier tube.

CO was measured using gas chromatography until May 1980. With this method, the air sample is first passed through a "stripper" chromatographic column where CO and methane are separated from other interfering pollutants. The CO and methane then pass through an "analysis" column where CO is separated from methane. The CO then passes through a catalytic CO-to-methane converter into a flame ionization detector, where the CO concentration is detected as methane. The current instrument uses nondispersive infrared (NDIR) methods to detect the CO.

In the NDIR method, infrared radiation from a hot filament is directed to a detector through two parallel cells — a reference cell filled with dry air or nitrogen and a sample cell through which sample air is continuously drawn. The difference in infrared absorption between the reference and sample cells creates a pressure imbalance in the detector. The imbalance, in turn, produces an electronic signal that is proportional to the concentration of carbon monoxide in the sample cell.

The chemiluminescence gas phase nitric oxide-ozone method is used to determine nitrogen oxides. This method is based on the gas phase chemical reaction of NO with O_3. The ambient air sample is mixed with a high concentration of ozone so that any NO in the air sample will react to produce light. The quantity of light is measured with a photomultiplier and converted into an electronic signal proportional to the NO concentration. To measure NO_x ($NO + NO_2$) concentrations, the air sample is first passed through a catalytic converter where any NO_2 in the sample is reduced to NO, and then into the reaction chamber for measurement, as described above. The NO_2 concentration is derived by subtracting the NO concentration measurement from the NO_x concentration measurement.

Until February 1980, SO_2 was continuously monitored by flame photometry. In flame photometry, sample air is drawn into a hydrogen flame where sulfur-containing molecules are excited to an activiated S_2 species. As activated S_2 reverts to a lower energy state, a broad band of radiation is emitted and measured by a photomultiplier tube, which produces an electronic signal proportional to the sulfur molecule concentration. Sulfides must be scrubbed from the air sample stream before being drawn into the flame if the sulfur concentrations are to be equivalent to sulfur dioxide concentrations. This measurement is now done using a pulsed fluorescent analyzer.

In pulsed fluorometry, sample air is drawn into a chamber and irradiated with pulsating ultraviolet light. Any SO_2 in the air stream passing through the chamber is excited to a higher energy state. As in the case of the flame photometer, the excited SO_2 then reverts to a lower energy state by emitting radiation which is measured by a photomultiplier tube.

Hydrocarbons were measured with a hydrogen flame ionization detector (FID). These measurements were discontinued in May 1980. In the FID, sample air is burned in the hydrogen flame creating a quantity of ions in proportion to the number of carbon atoms associated with hydrocarbon molecules in the air sample. The ions are collected on an electrode and detected with an electrometer which produces an electronic signal proportional to the ion collection rate. Since the FID is calibrated with respect to methane (CH_4), which has one carbon atom per molecule, the total hydrocarbon data are reported as parts per million carbon. Gas chromatography (GC) was used in conjunction with the flame ionization detector to measure the methane fraction of total hydrocarbons. In the anlysis for methane, the air sample is passed through chromatographic columns to separate methane from other hydrocarbons. Methane is then measured in the FID.

Total suspended partculates (TSP) are collected on an 8- by 10-inch glass fiber filter mounted in a flow-controlled high volume sampler. The filters

are exposed for 24 hours. The sampler flow rate is maintained at 45 standard cubic feet per minute. The filters are weighed before and after exposure to determine the total mass loading which is then converted to mass concentration using the flow rate. A co-located TSP sampler was installed in January 1980.

Wind speed, wind direction, dew point, and temperature are monitored at 10 meters above ground at all sites. As shown previously in Table 6-1, wind speed and wind direction are also measured at 20 and 30 meters above ground at Site A6. Wind variance is measured at 30 meters at this site and temperature at both 10 and 30 meters. The high-volume samplers collect air samples at approximately 4 meters above ground in compliance with PSD guidelines.

Gaseous pollutants are measured at approximately 3 meters above ground level. A Monitor Labs System 9400 data logger driving a Facit punch paper tape records the measurements.

6.1.2 Source Monitoring Program

In general, source monitoring will be performed in accordance with 40 CFR 60 — Standards of Performance for New Stationary Sources, Subparts J (Petroleum Refineries, including shale oil) and D (Fossil-Fuel Fired Steam Generators). SO_2 discharged into the atmosphere and H_2S in the product fuel gas will be continuously monitored at appropriate locations on the Claus sulfur/tail gas system in accordance with Methods 6 and 11, respectively. The steam generating unit will be continuously monitored for SO_2, NO_x, opacity, and either carbon dioxide or oxygen.

6.1.3 Future Program

As construction and operation phases approach, the air quality monitoring program will take on new objectives to:

- Quantitatively verify the predicted air quality impacts of oil shale development and operation on Tracts Ua and Ub

- Demonstrate that the impacts of the air contaminants emitted by the facilities are in compliance with National Ambient Air Quality Standards (NAAQS) and the Prevention of Significant Deterioration (PSD) provisions of the Clean Air Act, as well as with Utah air quality standards.

- Identify areas where additional control of air contaminant emissions would be appropriate or necessary

- Continue observing the long-term evolution of the regional air quality

This section describes the approach to air monitoring that will be used throughout all phases of the project and after decommissioning. It should be recognized that all of the air quality impacts of the development are not yet reliably quantifiable. As further modeling is performed to support permit applications and as data are collected during the growth of the facilities from phase to phase, some changes may be desirable. Changing environmental laws and the continuing evolution of measurement instruments also will provide a basis for change. The plan presented here represents the best projection possible at this time of the scope and detail needed for the air quality monitoring for the project.

The ambient air monitoring program will consist of four groups of measurements:

- Group I: Long-Term Air Quality Evolution. These are continuous measurements at fixed locations, at or near the sites of baseline-period stations whenever possible, to record the continuing long-term evolution of background and regional air quality. They will begin before construction, continue through all phases of operation, and terminate one year after decommissioning of all facilities and restoration of the environment.

- Group II: Direct Impact of Emissions. These are continuous measurements, either on- or off-tract, that are expected to document the greatest air quality impact, of

a particular aspect of the facility. (This group also includes meteorological measurements to help in determining plume transport.) Monitoring sites will be selected initially on the basis of experienced judgement supported by rational dispersion modeling; they may be moved as field surveys identify more appropriate locations and as new facilities are constructed. The number of sites will increase as the scale of the mining and retorting activities increases.

- Group III: Area Impact. These are continuous measurements generally off-tract, where the air pollution impact of the facilities could be noticeable (though at levels that are well below all standards or regulations), where the receptor could be sensitive (e.g., a residential community), or where the effect of an adjacent development on the quality of the airflow approaching the tracts could be significant. Such monitoring in the early phases of development would provide guidance for estimating the potential impacts of the later, larger-scale phases, and could serve as an input to their design.

- Group IV: Short-Term Intensive Studies. These are short-term detailed measurements to quantify the actual impact pattern of specific sources, to verify the adequacy of the model-based site selections for the monitoring stations, and to provide data for increasingly improved simulation modeling.

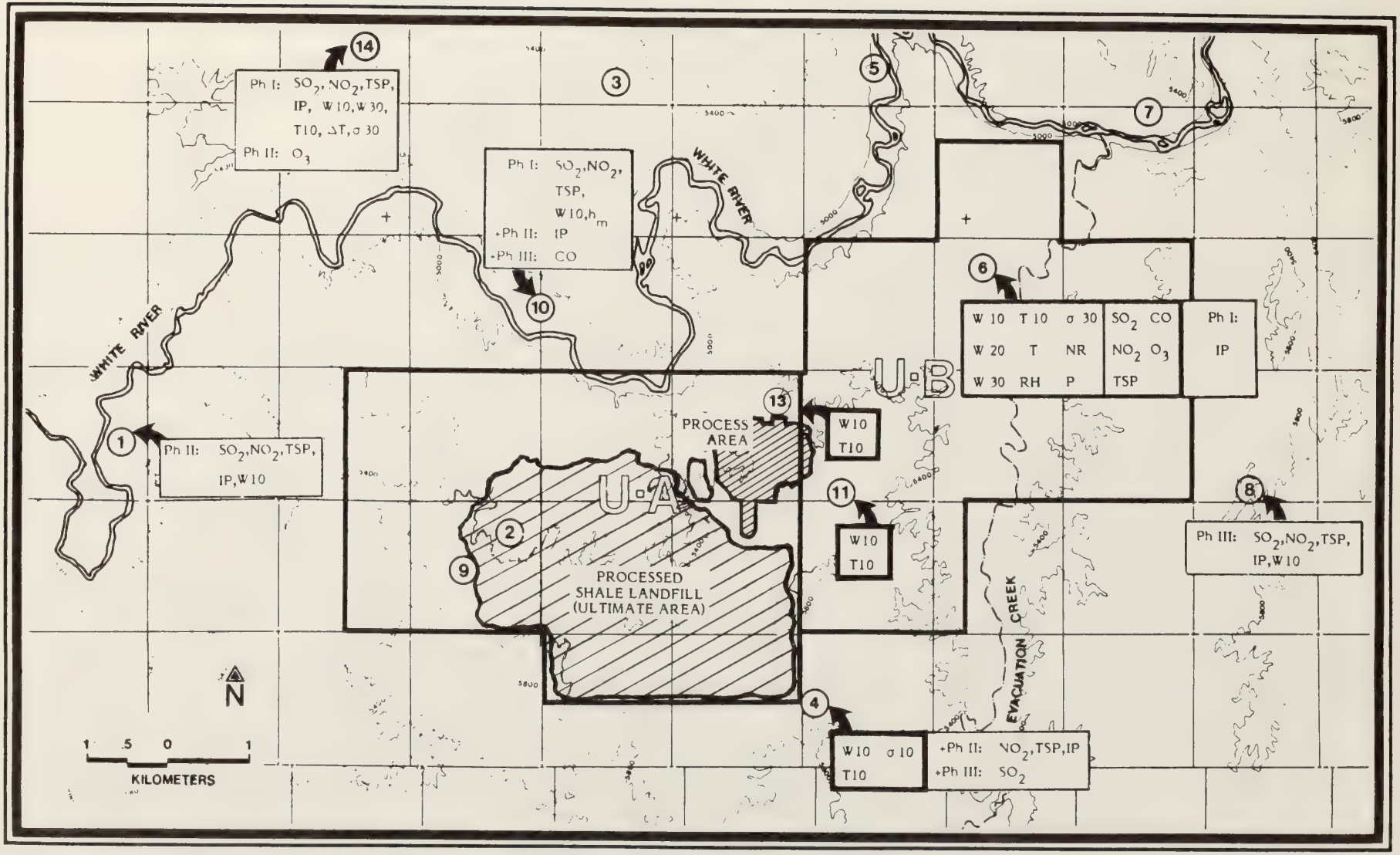
These measurements will provide more than just the minimum of data concerning compliance with air pollution regulations. They will also provide information about the air quality effects of oil shale development as this information accumulates concerning oil shale mining and retorting, and they may be modified as the scale of development and breadth of technical knowledge grow.

Table 6-2 summarizes the proposed monitoring program and Figure 6-3 shows the probable locations of the monitoring sites whose general positions can be predicted at this time. The specific location of Site A15 for regional visibility has not yet been selected. Note that several stations serve more than one function, depending on meteorology. Table 6-3 lists the data by development phase.

Table 6-2

AIR QUALITY AND METEOROLOGICAL MONITORING PROGRAM ON TRACTS Ua and Ub

Site Number	Measurement Group	Measurement	Beginning of Operation
A1	III	Regional air quality impact in drainage flows	Phase II
A4	II	On-tract meteorology	Currently operational
		Air quality impact south of plant and near processed shale pile	Phase II
A6	I	Background air quality	Currently operational
	II	Plant impact during some transition flows	Phase I
A8	III	Regional air quality impact	Phase III
A10 (relocated)	II	Air quality impact in drainage flows	Phase I Construction
A11	II	On-tract meteorology	Currently operational
A13 (relocated)	II	Plant area meteorology	Currently operational
A14 (new)	I	Background air quality	Phase I Operations
	II	Elevated plume impact during transitional meteorology	Phase I Operations
A15 (new; site to be selected)	I	Regional visibility	Phase I Operations



MEASUREMENTS INCLUDED IN CURRENT PROGRAM

MEASUREMENTS TO BE ADDED TO PROGRAM

MONITORING LOCATION (SITES 10 AND 14 ARE NEW SITES)

Note: Sites 2, 3, 5, 7, and 9 were baseline sites and are not now operational.

Figure 6-3 CONTINUOUS AIR QUALITY AND METEOROLOGICAL MEASUREMENT SITES ON TRACTS Ua AND Ub

Table 6-3

AIR QUALITY MONITORING PROGRAM ON TRACTS Ua and Ub BY DEVELOPMENT PHASE

Site Number	Present (1981)	Phase I[a]	Phase II	Phase III
Group I (Background)				
A6[b]	SO_2,NO_2CO,O_3,TSP W10,W20,W30,T10,ΔT,RH σ30,P,NR	Add IP	Continue	Continue[c]
A14[b]	—	SO_2,NO_2,TSP,IP,W10 W30,T10,ΔT,σ30	Continue	Add O_3
A15	—	C_r,b_s,TSP,IP,W10[d]	Continue	Continue
Group II (Impact)				
A4	W10,σ10,T10	Continue	Add NO_2,TSP,IP	Add SO_2
A10	—	SO_2NO_2,TSP,W10,h_m[e]	Add IP	Add CO
A11	W10,T10	Continue	Continue	Continue
A13	W10,T10	Continue	Continue	Continue
Group III (Area Impact)				
A1	—	-	SO_2,NO_2,TSP, IP,W10	Continue
A8	—	—	-	SO_2,NO_2,TSP, IP,W10

(a) Phase I monitoring begins before Phase I operation.
(b) Sites A6 and A14 also serve as Class II impact monitoring stations under specific meteorological conditions.
(c) Site A6 remains operational for 1 year after abandonment and reclamation.
(d) TSP, IP, and W10 measurements will not be needed at Site A15 if such data are available from another nearby site.
(e) Phase I monitoring for TSP and W10 will begin before Phase I construction.

6.2 AIR QUALITY

The objective of the air quality monitoring was to determine background levels in this pristine area. Monitoring at a number of locations in previous years has shown the data at Site A6 to be representative of pollutant levels throughout the tracts.

Most pollutant concentrations were very low, often near the detection threshold of the instrument, and well below any applicable standards. There were more activities on the tracts during 1975 to 1976. Air quality values for the last 3 years should be more representative of background and are used to establish baseline conditions for the analysis in line with EPA guidelines. However, all 6 years are discussed so that the general trends can be seen.

6.2.1 Gaseous Pollutants

Utah state air quality standards for gaseous pollutants are the same as the national standards. For reference in the ensuing discussions, Table 6-4 presents the National Ambient Air Quality Standards (NAAQS) for the various gaseous pollutants monitored on the tracts. The new standard of 235 $\mu g/m^3$ (0.12 ppm) for ozone went into effect on January 26, 1979. A new 1-hour CO standard of 29 mg/m^3 (25 ppm) has been proposed and is expected to be finalized early in 1981.

Over the sampling program period, except for sporadic occurrences of high levels of non-methane hydrocarbon (NMHC), the air on the tracts was generally free of gaseous pollutants. The only other pollutant present in measurable quantities was ozone, which has a natural non-zero background level. Otherwise, almost all instruments measuring gaseous pollutants were recording at their threshold limit most of the time. Specific comments are included with the discussion of each parameter.

Table 6-4

NATIONAL AND UTAH AIR QUALITY STANDARDS FOR GASEOUS POLLUTANTS

Pollutant	Averaging Time	Primary Standards	Secondary Standards
Ozone (O_3)	1-hour	235 $\mu g/m^3$ (0.12 ppm)	Same as primary
Carbon Monoxide (CO) (a)	8-hour	10 mg/m^3 (9 ppm)	Same as primary
	1-hour	40 mg/m^3 (35 ppm)	Same as primary
Sulfur Dioxide (SO_2)	annual average	80 $\mu g/m^3$ (0.03 ppm)	—
	24-hour	365 $\mu g/m^3$ (0.14 ppm)	—
	3-hour	—	1300 g/m^3 (0.5 ppm)
Nitrogen Dioxide (NO_2)	annual average	100 $\mu g/m^3$ (0.05 ppm)	Same as primary
Hydrocarbons (corrected for methane - NMHC)	3-hour (6-9 a.m.)	160 $\mu g/m^3$ (0.24 ppm)	Same as primary

(a) New 1-hour national standard is 25 mg/m^3 is expected to go into effect early in 1981.

Ozone (O_3). Figure 6-4 shows plots of diurnal variations of O_3 at Site A6 for January and July. The average diurnal trend has lower values in the early morning and higher values in the afternoon. This trend closely follows the diurnal temperature values, showing the close relationship between sunlight and ozone formation.

The peak hour, second highest hour, and average annual values at Site A6 are tabulated in Table 6-5. The highest and second highest hourly values observed were both 160 $\mu g/m^3$ during 1977. The annual average values varied between 63 $\mu g/m^3$ and 73 $\mu g/m^3$.

Figure 6-5 shows the trend in the monthly averages of ozone at Site A6 since 1975. The highest monthly average of 97 $\mu g/m^3$ occurred in February 1979. In general, the highest ozone values occur during late spring and summer, with occasional high concentrations occurring during the late winter. The ozone concentrations at Site A6 have been found by Chan and Smith (Ref. 6-5) to depend a great deal on the ozone content of the troposphere. Year-to-year variability correlates with the passage of fronts over the site. Unusually high ozone concentrations (>100 $\mu g/m^3$) can be attributed to long-range transport from urban areas, strong turbulent atmospheric mixing that brings ozone from aloft to the surface, or ozone intrusion accompanying a frontal passage.

The nominal detection limit for the ozone anlyzer is 2 $\mu g/m^3$ and the instrument's precision is ±10 $\mu g/m^3$.

Carbon Monoxide (CO). Table 6-6 gives the highest and second highest 1-hour and 8-hour and annual average CO concentrations at Site A6. The maximum 1-hour concentration observed was 3.0 mg/m^3, occurring in 1975 and 1976, and the maximum 8-hour reading was 1.8 mg/m^3 occurring in 1976. All values were well below the national standards of 40 mg/m^3 (1-hour) and 10 mg/m^3 (8-hour).

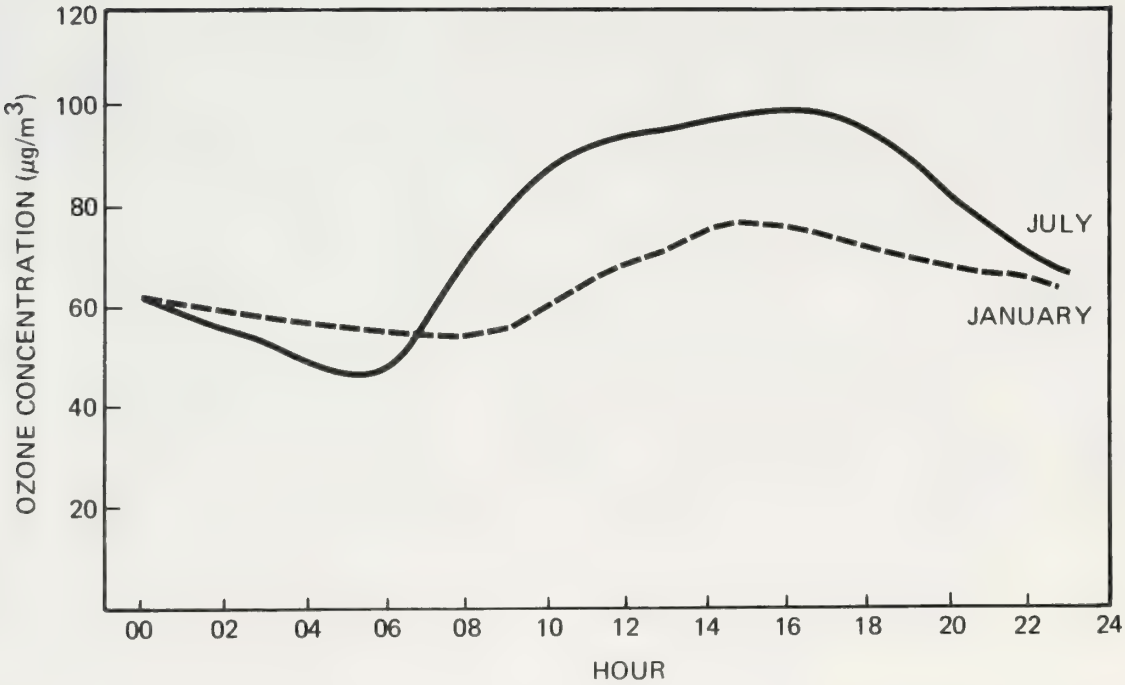


Figure 6-4 DIURNAL VARIATIONS OF MEAN OZONE CONCENTRATION AT SITE A6 DURING JANUARY AND JULY 1975 TO 1980

Table 6-5

OZONE READINGS AT SITE A6 FOR 1975-1980[a]
($\mu g/m^3$)

Reading	1975	1976	1977	1978	1979	1980
Highest, 1 hour	150	140	160	137	151	143
Second highest, 1 hour	150	140	160	135	149	143
Annual average	70	63	61	72	73	69

(a) Ozone standard is 235 $\mu g/m^3$.

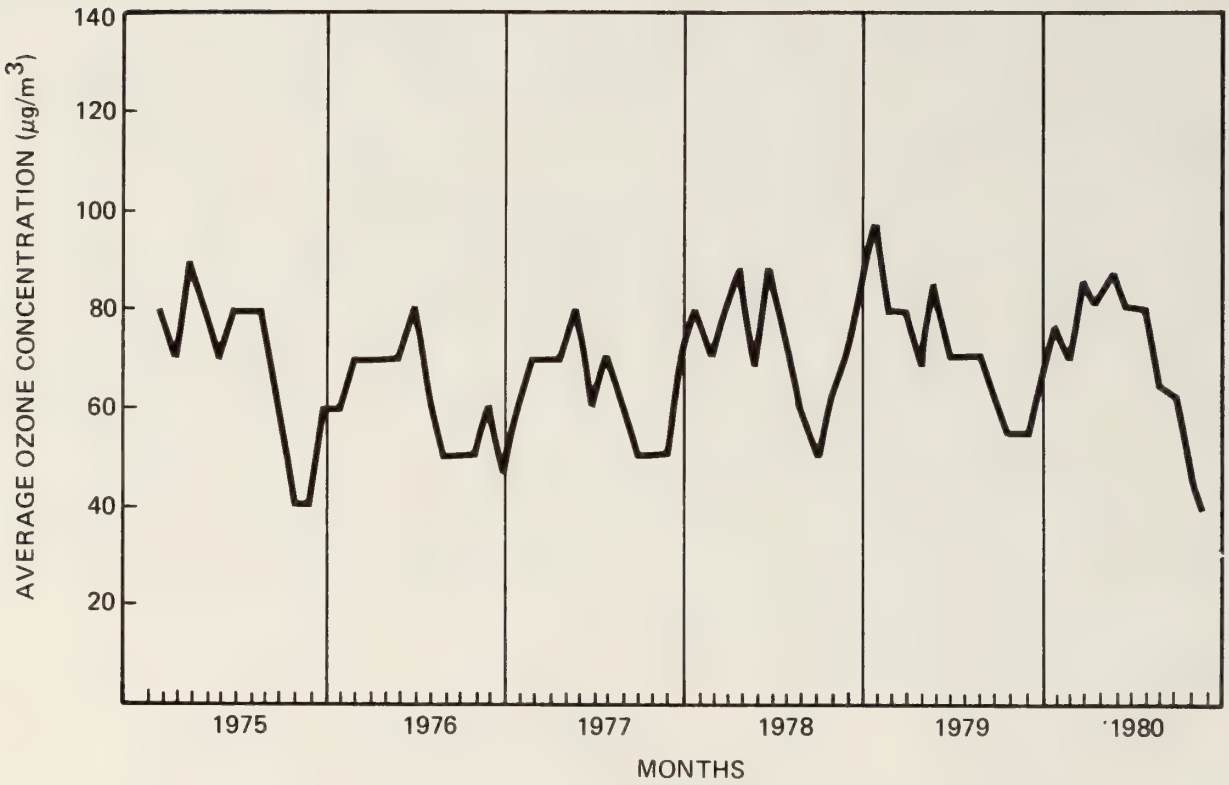


Figure 6-5 TREND OF MONTHLY AVERAGE OZONE AT SITE A6 FROM FEBRUARY 1975 TO DECEMBER 1980

The normal U.S. background level is 0.5 mg/m^3 and practically all the readings fall around and below this value. No diurnal or seasonal variations were observed in the CO levels. Readings were generally near the detection limit of the instrument, 0.1 mg/m^3. The precision of the instrument is ±0.1 mg/m^3.

Nitrogen Dioxide (NO_2). Of the nitrogen oxides, only NO_2 has a national ambient air quality standard (annual average of 100 $\mu g/m^3$). Table 6-7 shows the annual averages and the highest and second highest 1-hour values. The highest 1-hour value was 100 $\mu g/m^3$, recorded during 1975. The second highest value was 80 $\mu g/m^3$, again recorded in 1975. The annual averages ranged from 0 to 5 $\mu g/m^3$.

The precision of the NO_x instrument is ±20 $\mu g/m^3$; readings are generally below this value and near its lower detection limit of 5 $\mu g/m^3$.

Sulfur Dioxide (SO_2). Table 6-8 gives the highest, second highest 3- and 24-hour, and annual average readings of SO_2. No seasonal or diurnal trend has been evident and most values are near the instrument's detection limit of 25 g/m^3. The highest 3-hour SO_2 reading of 113 $\mu g/m^3$ was recorded during 1979. The second highest reading of 47 $\mu g/m^3$ was also recorded during 1979. The standard for a 3-hour averaging time is 1,300 $\mu g/m^3$. The highest and second highest 24-hour SO_2 reading were 14 $\mu g/m^3$ and 13 $\mu g/m^3$, both recorded during 1978. These readings are well below the 24-hour standard of 365 $\mu g/m^3$. The annual average on the tracts ranged from 0 to 3 $\mu g/m^3$ as compared to the annual standard of 80 $\mu g/m^3$. The precision of the instrument is ±10 $\mu g/m^3$.

Hydrogen Sulfide (H_2S). Most hourly reading of H_2S were below the instrument's detection limit of 10 $\mu g/m^3$. Table 6-9 gives the highest 1-hour, second highest 1-hour and annual average values. No diurnal or seasonal trends are evident. The highest and second-highest hourly values were 35 $\mu g/m^3$ in 1975. Annual averages ranged from 0 to 8 $\mu g/m^3$. The precision of the instrument is 10 $\mu g/m^3$.

Table 6-6

CARBON MONOXIDE READINGS AT SITE A6 FOR 1975-1980[a]
(mg/m^3)

Reading		1975	1976	1977	1978	1979	1980
1-hour	Highest	3.0	3.0	1.0	0.7	1.8	2.5
	Second highest	2.2	2.7	0.9	0.6	0.9	1.9
8-hour	Highest	1.3	1.8	0.6	0.4	0.5	1.5
	Second highest	1.2	1.7	0.6	0.4	0.5	1.4
Annual average		0.2	0.1	0.2	0.1	0.1	0.4

(a) One-hour carbon monoxide standard is 40 mg/m^3; eight-hour standard is 10 mg/m^3.

Table 6-7

NITROGEN DIOXIDE CONCENTRATIONS AT SITE A6 FOR 1975-1980[a]
($\mu g/m^3$)

Reading	1975	1976	1977	1978	1979	1980
Highest, 1 hour	100	70	10	15	30	21
Second highest, 1 hour	90	50	10	13	30	19
Annual average	5	5	0	1	1	2

(a) The annual average NO_2 standard is 100 $\mu g/m^3$.

Table 6-8

SULFUR DIOXIDE CONCENTRATIONS AT SITE A6 FOR 1975-1980[a]
($\mu g/m^3$)

Reading		1975	1976	1977	1978	1979	1980
3-hour	Highest	15	7	17	25	113	17
	Second highest	12	7	15	25	47	16
24-hour	Highest	10	5	10	14	14	9
	Second highest	10	0	5	13	6	8
Annual average		3	0	1	3	0	1

(a) The SO_2 annual average standard is 80 $\mu g/m^3$, 24-hour standard is 365 $\mu g/m^3$, and secondary 3-hour standard is 1300 $\mu g/m^3$.

Table 6-9

HYDROGEN SULFIDE CONCENTRATIONS AT SITE A6 FOR 1975-1979[a]
($\mu g/m^3$)

Reading	1975	1976	1977	1978	1979
Highest, 1 hour	35	10	10	10	8
Second highest, 1 hour	35	5	5	5	4
Annual average	8	2	0	1	0

(a) Instrument removed in early 1980.

Non-Methane Hydrocarbon (NMHC). The only pollutant that exceeded any of the NAAQS was non-methane hydrocarbons (NMHC). However, this standard was developed as a guideline for controlling ozone pollution in urban areas, and not as a health standard. High NMHC values are frequently observed in remote areas, and the high levels on the tracts are not uncommon. These observations could be due to precision problems with the instrument used to measure hydrocarbons, since errors of up to 80 percent of the standard are possible. The precision of the Beckman Instruments' gas chromatograph that is used for the analysis of hydrocarbons is 0.1 ppm (65 $\mu g/m^3$) for THC (total hydrocarbons) and 0.1 ppm for CH_4 (methane). To obtain NMHC, the CH_4 reading is subtracted from the THC reading. This can compound possible error to about 0.2 ppm (130 $\mu g/m^3$. The range of instrumentation precision is in the same magnitude as the standard (160 $\mu g/m^3$), even when perfectly calibrated, and probably accounts for many of the observed high readings.

However, the EPA-prescribed reference method for measuring non-methane hydrocarbons is by flame ionization detection and gas chromatography, exactly as used in the Beckman instrument, and the measurement procedures used during the program are the best available. This inconsistency between the ambient air quality standard and the instrumentation technique is recognized by the EPA. In early 1978, the EPA issued a letter discouraging the monitoring of NMHC on oil shale lease tracts. Following EPA's suggestion, and with the approval of the Deputy Conservation Manager — Oil Shale, total hydrocarbons (THC) and methane (CH_4) were monitored until May 1980, but NMHC values were not analyzed. These measurements were discontinued after May 1980.

6.2.2 Particulate Pollutants

Particulate concentrations are monitored by high-volume samplers which sample over a period of 24 hours once every 6 days. The size of the particulate matter collected by the samplers ranges from below 1 μm to 30 μm, the value determined to be the effective aerodynamic cut-off diameter for capture of airborne dust. Table 6-10 gives the national and state standards.

Total Suspended Particulates (TSP). Table 6-11 gives the geometric means and maximum 24-hour averages of the total suspended particulate concentrations at Site A6 by season. None of the recorded values reached the standards. The geometric mean can be considered to correspond to the maximum concentration expected at a 50 percent frequency because particulate concentrations are generally log-normally distributed. The annual geometric mean of particulate concentrations ranged from 24.5 $\mu gm/^3$ in 1975 to 12.5 $\mu g/m^3$ in 1977. These values are much lower than the secondary standard of 60 $\mu g/m^3$.

The most stringent short-term TSP standard is the national 24-hour secondary standard, which sets the upper limit at 150 $\mu g/m^3$. The highest such value measured at Site A6 was 127.0 $\mu g/m^3$ in 1980.

Trace Elements. A set of size-fractionated particulate samples was collected during 1975 at Site A2 by a Multistage Lundgren impactor for analysis of trace elements using ion-excited x-ray emission techniques at 50 microcoulombs. Analysis results indicate the presence of Li, Be, B, Na, Mg, Al, Si, S, Cl, K, Ca, Ti, V, Cr, Mn, Fe, Co, Ni, Cu, Zn, As, Se, Br, Rb, Sr, Zr, Ba, Pt, Au, Hg, and Pb. Most of the elements, with the exception of normal soil constituents, were found at concentrations less than or around 10 $\mu g/m^3$, with most of the mass generally found in the smaller size fractions (.10 - .65 μm).

The elements that existed in larger quantities were Al, Si, S, K, Ca, and Fe. Concentrations of typical anthropogenic aerosols such as Cu, Zn, and the automotive-derived aerosols of Br and Pb were very low, at only a few percent of typical urban values. Lead is the only one of the elements for which there is a national ambient air quality standard. Lead was not monitored during the last 3 years, but data from 1975 to 1976 suggest that on-tract concentrations are well below the standard.

In summary, the annual averages of all the pollutants measured during 1975 and 1979 are presented in Table 6-12.

Table 6-10

NATIONAL AND UTAH STATE AMBIENT AIR QUALITY STANDARDS
FOR PARTICULATE MATTER
($\mu g/m^3$)

Pollutant	Averaging Time	Standard	
		Primary	Secondary
Total Suspended particulate matter	Annual geometric mean	75	60
	24-hour	260	150
Lead	Calendar quarter	1.5	1.5

Table 6-11

PARTICULATE CONCENTRATIONS AT SITE A6 FOR 1975-1980
($\mu g/m^3$)

Season	Geometric Mean					
	1975	1976	1977	1978	1979	1980
Winter	—	14.2	13.2	7.2	9.2	9.3
Spring	17.2	17.2	22.2	14.2	8.1	15.1
Summer	39.2	34.8	27.6	27.2	19.0	27.9
Fall	17.2	37.1	22.9	21.3	16.4	37.2
Annual	24.5	23.5	22.2	15.0	12.5	19.6
	Maximum 24-Hour Average					
Winter	—	51.9	32.6	13.0	19.6	34.2
Spring	52.0	45.1	58.3	47.7	34.3	64.6
Summer	74.7	63.9	47.2	45.2	35.8	41.3
Fall	52.8	101.2	51.4	62.7	52.9	127.0

Table 6-12

ANNUAL AVERAGES FOR GASEOUS POLLUTANTS AND ANNUAL GEOMETRIC MEAN FOR TSP AT SITE A6 FOR 1975-1980 ($\mu g/m^3$)

Pollutant	Annual Averages						Average	Standard
	1975	1976	1977	1978	1979	1980		
O_3	70	63	61	72	73	69	68	—
CO (mg/m^3)	0.2	0.1	0.2	0.1	0.1	0.4	0.2	—
NO_2	5	5	0	1	1	2	2	100
SO_2	3	0	1	3	0	1	1	80
H_2S	8	2	0	1	0	—	2	—
Total suspended particulates	24.5	23.5	22.2	15.0	12.5	19.6	19.6	60
Lead	0.04	0.09	—	—	—	—	0.07	—

6.2.3 Visibility

During the first years of monitoring (1975 and 1976), visibility was measured on the tract at Site A9 using photographs, and at Site A2 by measuring the scattering of light by airborne particles.

The lowest visibilities (highest scattering) were generally observed during the stable night and early morning hours. During the afternoons, when wind and human activities would tend to increase the dust emissions into the air, better ventilation and mixing tended to counteract any visibility degradation.

From a seasonal standpoint, the best visibilities were observed during the fall. The lowest scattering (best visibility) observed in 1975 to 1976 was

$b_s = 0.02 \times 10^{-3} m^{-1}$,* which roughly corresponds to a local visual range of 150 miles (235 km). The minimum visual range of 18 miles (29 km) was measured in the spring ($b_s = 0.10 \times 10^{-3} m^{-1}$). The average visual range in 1975 was much lower than in 1976, with averages of 64 miles and 81 miles, respectively. Since very small increases in atmospheric fine particulate matter concentrations have a strong impact on the visibility in clean areas, this large difference is probably a consequence of human activity near Site A2 during the first year of the monitoring program. Seasonal visual ranges are given in Table 6-13. In general, these readings correspond to very good visibility, with an absence of human-caused haze in the area.

Table 6-13

LOCAL VISUAL RANGE VALUES AT SITE A2 FROM 1975 TO 1976[(a)]

Season	Visual Range Value (miles)			Number of Observations
	Maximum	Minimum	Average	
Winter	150	29	70	3,778
Spring	150	18	78	3,805
Summer	150	27	65	3,807
Fall	150	31	89	4,345

(a) Determined from integrating nephelometer measurements.

* Measured at a wavelength of light of approximately 500 nanometers.

6.3 METEOROLOGY

The objectives of the meteorological measurements were to define meteorological conditions, determine trends, and verify the data for future air pollutant dispersion modeling work. Meteorology data differ from air quality data in that any year can be significantly different from the rest. Additional years of monitoring give a more general data base, which includes various climatological conditions. The following discussion on meteorology is based on data collected during 1975 through 1980.

6.3.1 Meteorological Parameters

Surface Flow. The rugged terrain featured in the area complicate the airflow pattern. Table 6-14 shows the prevailing direction and speed by month for the four wind sites. Spatial variation in wind speed on the tracts was also observed. Generally, nighttime drainage flow is prevalent throughout the year. Figure 6-6a shows the typical airflow streamlines for the early morning drainage pattern. The solid arrows on this figure are wind vectors at the monitoring sites, and the longer lines are estimated flow streamlines. The large open arrow depicts the mesoscale flow direction in the greater White River drainage basin. The drainage pattern does not deviate significantly throughout the year. This figure was prepared from averaged wind observations at the four wind sites through the years. The drainage flow is always from higher to lower terrain.

Figure 6-6b shows an upslope pattern that is transitional between drainage and synoptic flow. The surface-based inversion that results from strong radiative cooling begins to lose some of its strength shortly after sunrise. As the morning progresses, the heat gained by the surface from solar radiation exceeds that lost by terrestrial radiation and the soil temperature rises, warming the air above. This creates a pressure difference resulting in upslope flow. This pattern is transitional and generally lasts less than an hour, but is important to the understanding of dispersion of pollutants since plume

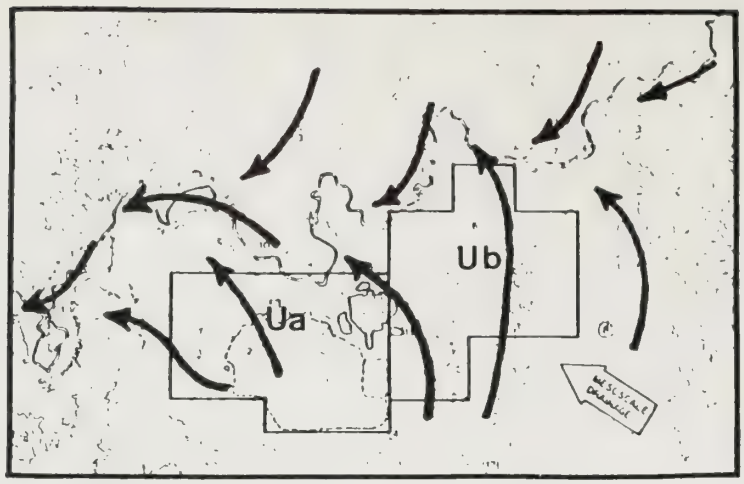
Table 6-14

AVERAGE MONTHLY WIND SPEED AND PREVAILING DIRECTION FROM 1975 TO 1980[a]

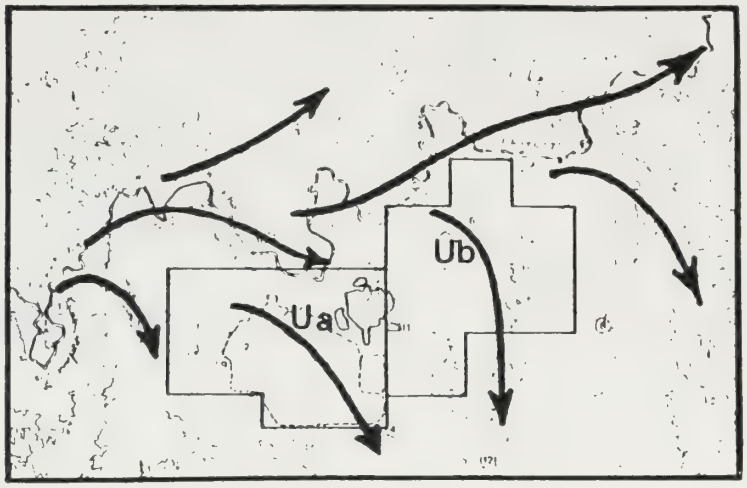
Month	Site A4			Site A6			Site A11			Site A13		
	Direction	Speed		Direction	Speed		Direction	Speed		Direction	Speed	
		(mph)	(m/s)		(mph)	(m/s)		(mph)	(m/s)		(mph)	(m/s)
January	W	4.7	2.0	W	4.4	1.9	VAR	4.3	1.9	W	2.7	1.2
February	W	5.1	2.3	W	5.3	2.4	NW	5.1	2.3	W	2.9	1.3
March	W	6.8	3.0	SE	7.2	3.2	SE	6.7	3.0	W	4.7	2.1
April	W	7.8	3.5	SSE	8.6	3.9	SE	7.8	3.5	VAR	5.8	2.6
May	SW	7.8	3.5	SSE	9.2	4.2	SE	8.1	3.6	SE	6.3	2.8
June	SW	8.5	3.8	SSE	9.8	4.4	SE	8.5	3.8	WNW	6.9	3.1
July	WNW	7.2	3.2	SSE	7.8	3.5	SE	7.6	3.4	SE	5.8	2.6
August	WNW	7.5	3.3	SSE	8.2	3.4	SE	7.8	3.5	SE	6.3	2.8
September	WNW	6.7	3.0	SSE	7.3	3.3	SE	7.4	3.3	SE	5.4	2.4
October	WNW	5.8	2.6	SE	6.6	3.0	SE	6.3	2.8	SE	4.0	1.8
November	W	5.2	2.3	SE	5.8	2.6	VAR	5.4	2.4	VAR	3.8	1.7
December	W	5.3	2.4	SE	4.9	2.2	VAR	4.7	2.1	ESE	3.4	1.5
Annual	W	6.5	2.9	SSE	7.2	3.2	SE	6.7	3.0	SE	4.9	2.2

(a) Direction from which the wind comes:

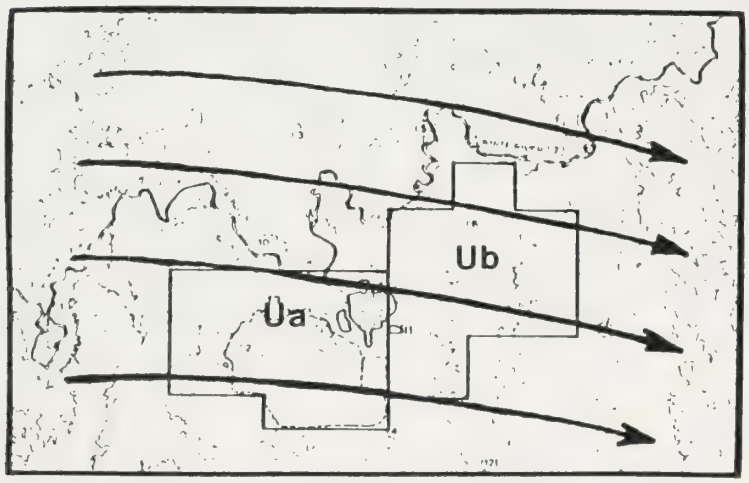
W = west
S = south
N = north
E = east
VAR = variable



a. DRAINAGE FLOW DURING EARLY MORNING HOURS



b. TRANSITIONAL FLOW



c. AFTERNOON SYNOPTIC FLOW

5 MPH (2.2 M/S)
WIND VECTOR
STREAMLINE

Figure 6-6 TYPICAL AIR FLOW PATTERNS ON TRACTS Ua AND Ub

fumigation could occur under this condition. Because of its brevity, this pattern is lost in the hourly-average wind direction. This pattern begins earlier during longer summer daylight hours than during the winter.

Figure 6-6c shows the afternoon streamlines on the tracts. Very little directional difference is noted except the average speeds are higher during the summer. This is the average synoptically induced flow encountered in this portion of Utah throughout the year.

Figure 6-7 gives the 6-year average diurnal wind speeds for January and July. The January speeds are practically the same throughout the day. The wind speeds between 0800 and 1200 MST are only slightly lower than during the rest of the day. The July wind speeds generally reach an average peak of about 5 m/s (11 mph) between 1400 and 1800 MST.

Figure 6-8 indicates wind speed changes throughout the year, and shows the monthly average wind speeds and standard deviations, along with the peak wind speed for each month at Site A6. The average wind speeds increase through spring and decrease thereafter. The peak wind during 1975 through 1980 of 19 m/s (42.5 mph) occurred during June 1976.

Figure 6-9 shows the directional wind roses at the monitoring stations on the tracts using the mid-month of the four seasons (January, April, July, and October). Although individual months showed different prevailing directions, SSE was the most prevalent direction at Site A6 throughout the entire 5 year period. The frequency of the SSE wind is a direct result of the drainage flow predominating at Site A6.

Temperature. Temperature was measured at several locations on the tracts. These locations varied from seven during the first year to four during the last 4 years. Some spatial variations, generally attributable to topography, were evident from these data. Site A10 (operating only in the first 2

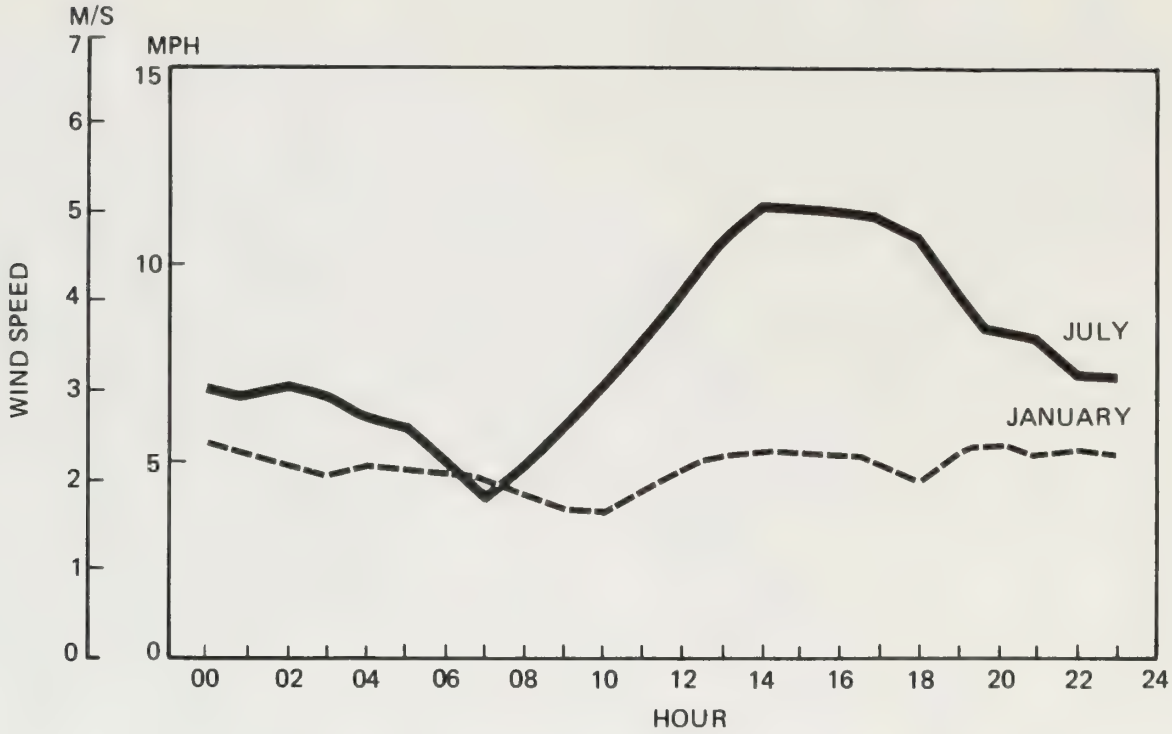


Figure 6-7 DIURNAL VARIATION OF MEAN WIND SPEED AT SITE A6 IN JANUARY AND JULY FROM 1975 TO 1980

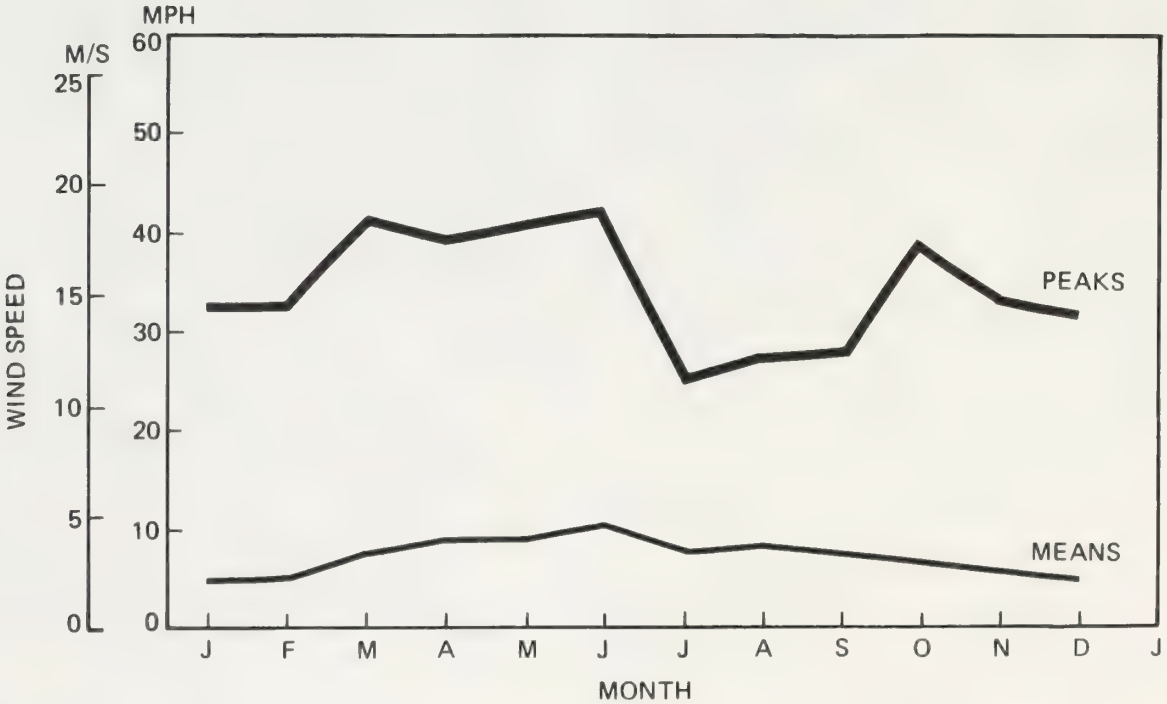
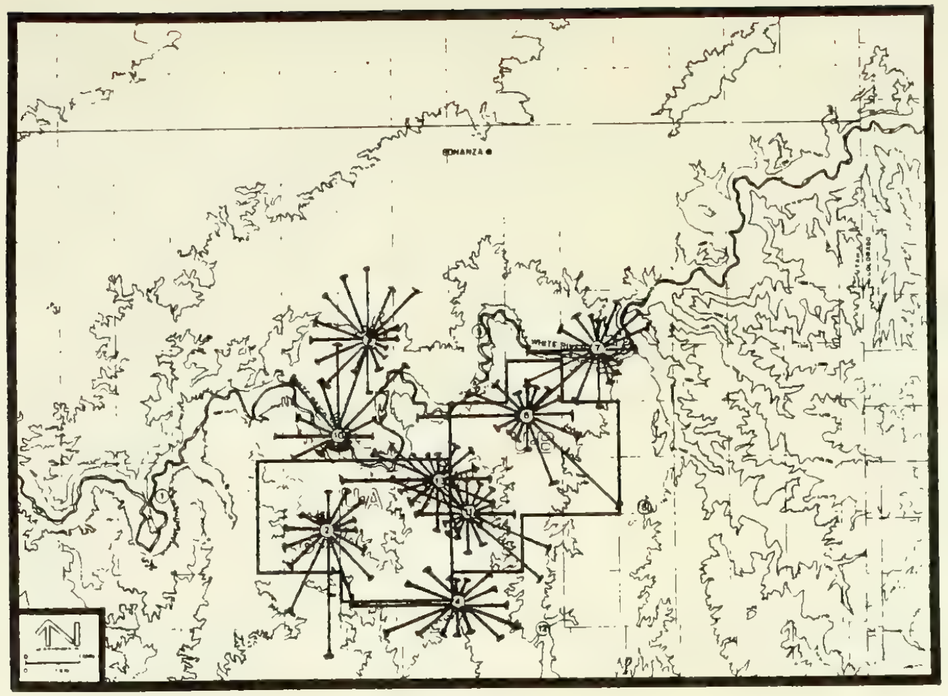
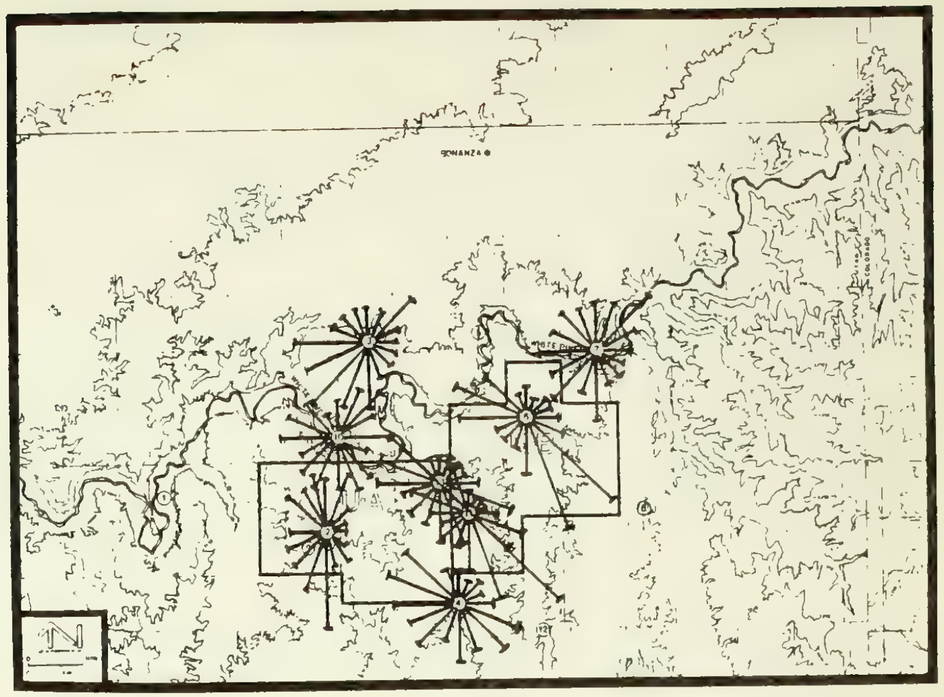


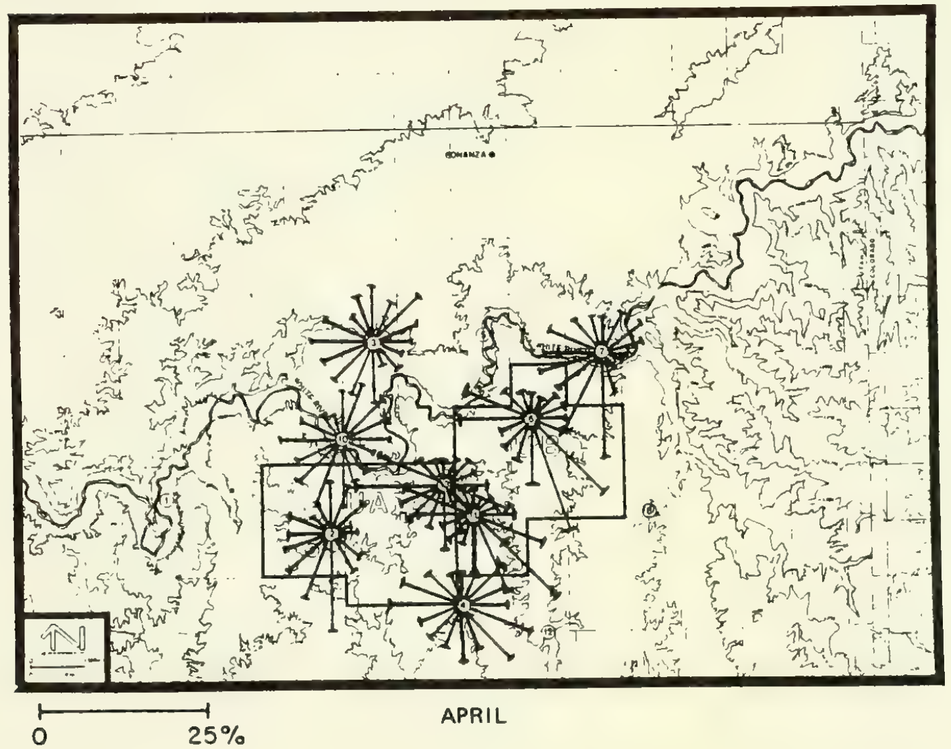
Figure 6-8 MONTHLY MEAN AND PEAK WIND SPEEDS AND THEIR STANDARD DEVIATIONS AT SITE A6 FROM 1975 TO 1980



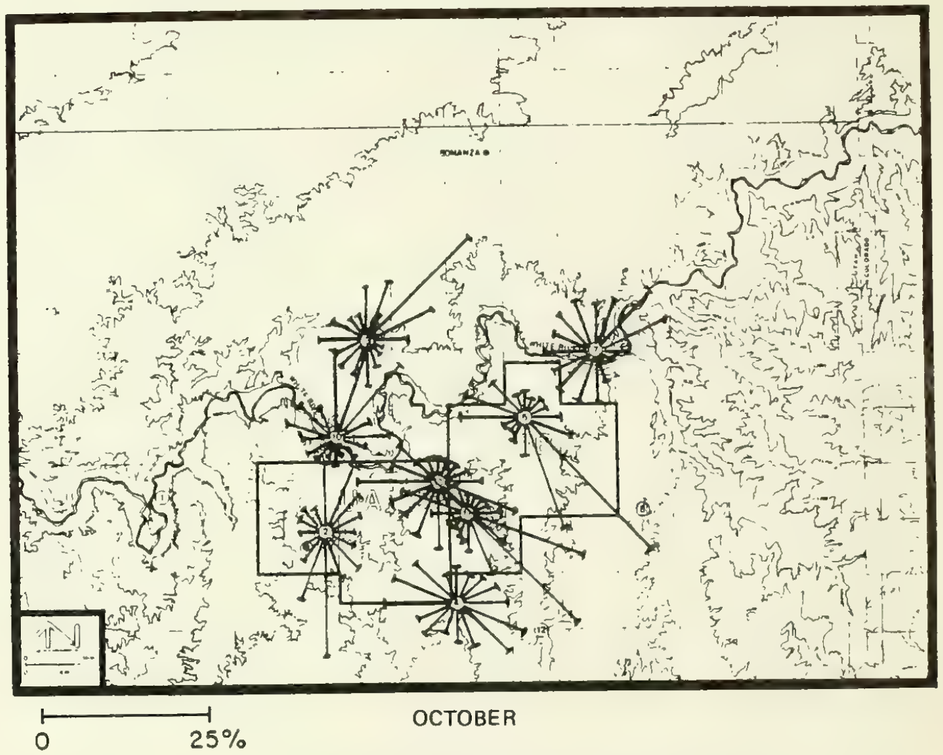
JANUARY



JULY



APRIL



OCTOBER

Figure 6-9 DIRECTIONAL WIND ROSES (THE LENGTH OF EACH BAR REPRESENTS THE FREQUENCY OF WINDS FROM THE DIRECTION TOWARD WHICH THE BAR POINTS.)

years) consistently registered a lower temperature than the others because it was in a protected valley just north of Tract Ua along the White River.

Site A6 was the location of a 30-meter (100-foot) tower that recorded temperatures at three levels. Figure 6-10 shows the average diurnal variation in temperature for January and July for the 10-meter (33-ft) level at this site during the 6-year period. Minimum temperatures were usually recorded during January, with the maximums usually recorded in July.

The diurnal variation shown in this figure is very similar to that observed in other months and at other sites. The daily maximum temperature was generally measured between 1400 and 1500 MST, while the minimum was usually between 0400 and 0500 MST.

Monthly average temperatures for the same site and period are shown in Figure 6-11. Average monthly minimums and maximums are also shown. These values did not vary much from year to year. Temperatures at this site varied from a low of -30C (-22F) during January 1979 to a high of 36C (97F) in July of 1976 and 1978 and August 1979. The average temperature for all years was 8C (45F).

Precipitation. A network of precipitation gauges was established on or near Tracts Ua and Ub to monitor annual precipitation. The network was first established in the last quarter of 1974, and ranged from two gauges to 13 gauges that were operated throughout the year.

From data collected thus far, two major factors appear to account for the variations in annual precipitation amounts from station to station. The primary factor is the variation in terrain. In general, monitoring indicated that precipitation was heavier on ridgetops and lighter in valleys. It has been determined that this orographic effect will produce approximately a

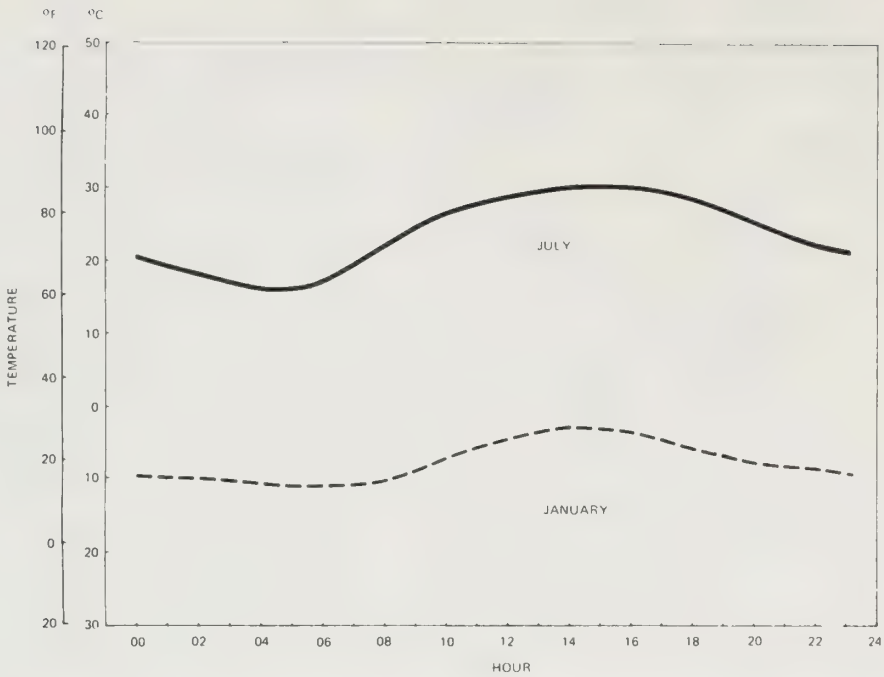


Figure 6-10 DIURNAL VARIATION OF MEAN HOURLY TEMPERATURES AT SITE A6 FROM 1975 TO 1980

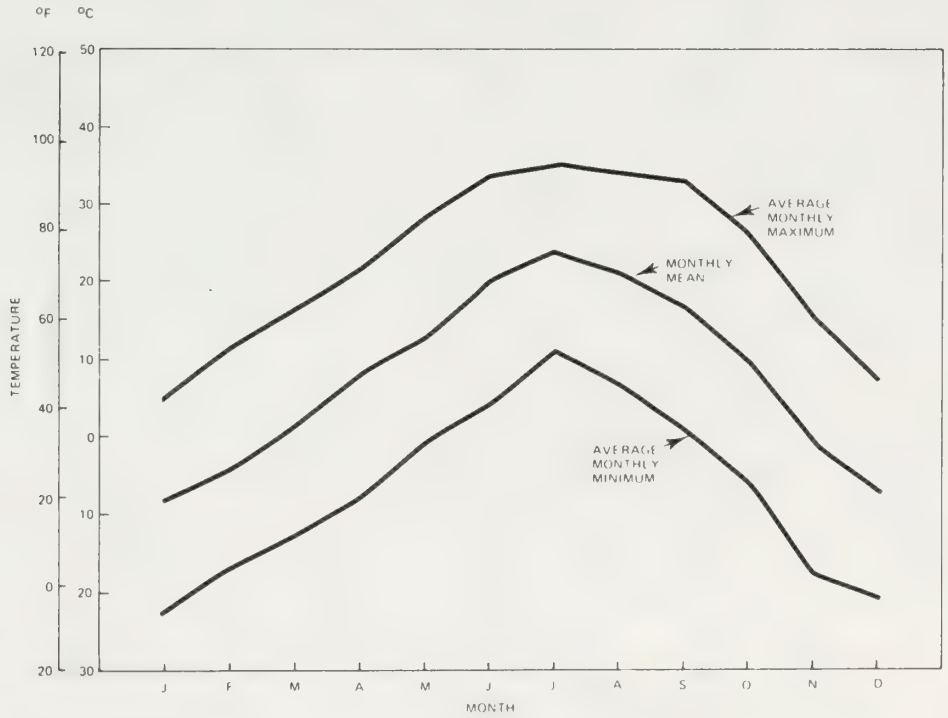


Figure 6-11 AVERAGE MONTHLY MAXIMUM AND MINIMUM AND MONTHLY MEAN TEMPERATURE AT SITE A6 FROM 1975 TO 1980

3-inch increase in precipitation per 1,000 foot increase in elevation. The annual average precipitation ranged from 27.69 centimeters (10.90 in.) for the highest station to 21.13 centimeters (8.36 in.) for the lowest station.*

The second factor is the slow-moving, intense, isolated thunderstorms that cross the tracts. The effects of these storms may override the orographic effects at some stations, giving the data a uniform appearance.

Historical data from Bonanza, Utah, near the northern edge of Tracts Ua and Ub show that Bonanza has an average precipitation of 20.3 centimeters (8.0 in.), while Tracts Ua and Ub have an annual average of approximately 22.9 centimeters (9.0 in.).

Evaporation. Evaporation from ground pans was measured in Southam Canyon (Site A2) from 1975 through 1980 and on a ridge above Evacuation Creek Site A6) during 1975 and 1976. This second station was moved (prior to the 1977 season) to the proposed plant site (Site A13), and collected data through 1980.

Evaporation data collected for the freeze-free period, approximately May through September, indicated an average total pan evaporation of approximately 94 centimeters (37 in.) for the Southam Canyon location. The data collected to date have not conclusively defined variations of evaporation throughout the tracts. It is apparent that pan evaporation rates at various locations depend on elevation, wind run, and other factors.

Relative Humidity

Relative humidity was measured throughout the 6-year period. In general, the relative humidity on the tracts is lower in summer than in winter.

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* The annual average precipitation values were determined for 8 gauge locations for the water years 1975 to 1979. The missing records were estimated based on data collected at the other locations and on topographic relationships.

The highest readings are found in winter from 0400 through 0800 MST and averaged above 80 percent. The lowest readings occur from 1400 to 1700 MST in the summer, with values around 25 percent.

The diurnal variation of relative humidity is approximately the reciprocal of temperature, indicating that the amount of moisture in the air remains fairly constant during a typical day on the tracts. Figure 6-12 shows the average diurnal variation in relative humidity in January and July from 1975 to 1980. These values are fairly typical for each of the 6 years.

Barometric Pressure. Barometric pressure is an indicator of the position and intensity of major weather systems passing over the tracts. Both the highest and lowest values of pressure generally occur from October to April in conjunction with the passage of winter storms and the presence of the Basin High. During the summer, the air mass systems are much weaker, and the pressure consequently exhibits less fluctuation.

The pressure on the tracts from 1975 to 1980 averaged 631 millimeters (24.84 in.) of Hg. The highest pressure was 646 millimeters (25.43 in.) of Hg in November 1975 and 1979, and the lowest was 614 millimeters (24.17 in.) during March and April 1975 and January 1980.

Heat Flux. Heat flux was determined on the tracts by measuring the net thermal radiation at Site A6. This parameter is the amount of heat received by the sun minus the amount lost by the earth during radiative cooling. This factor affects the stability of the atmosphere, and the solar radiation influences the rate of various photochemical processes.

Figure 6-13 shows the average hourly net thermal radiation on the tracts during January and July from 1975 to 1980. (January 1975 and July 1979 were not included because of instrument problems.) As would be expected, the solar radiation is higher in the summer due to longer days, more intense

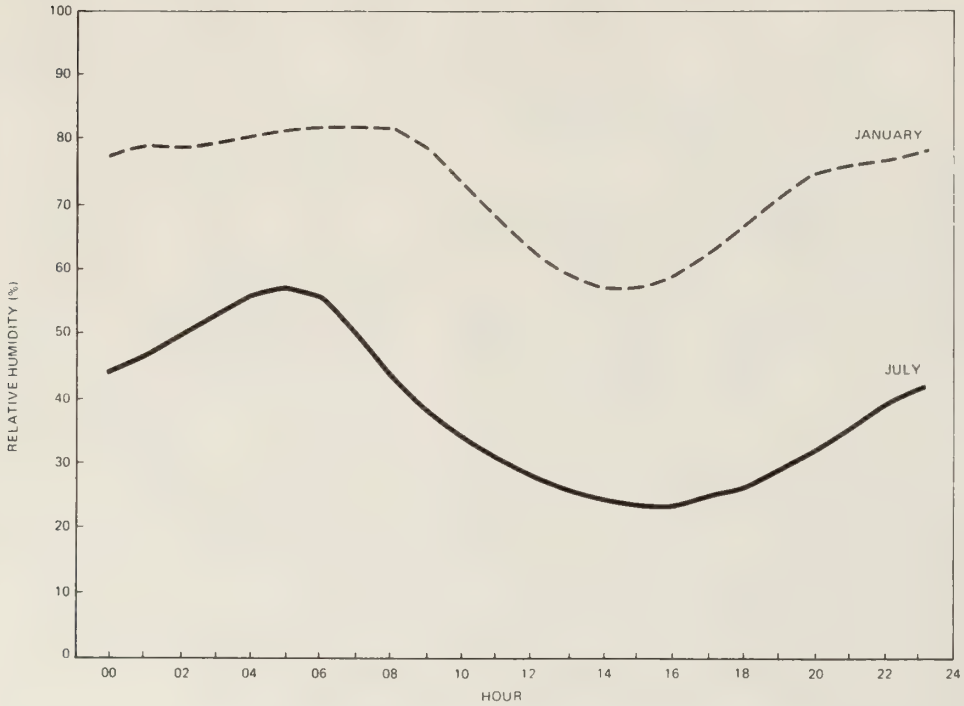

Figure 6-12 DIURNAL VARIATION OF MEAN RELATIVE HUMIDITY AT SITE A6 IN JANUARY AND JULY FROM 1975 TO 1980

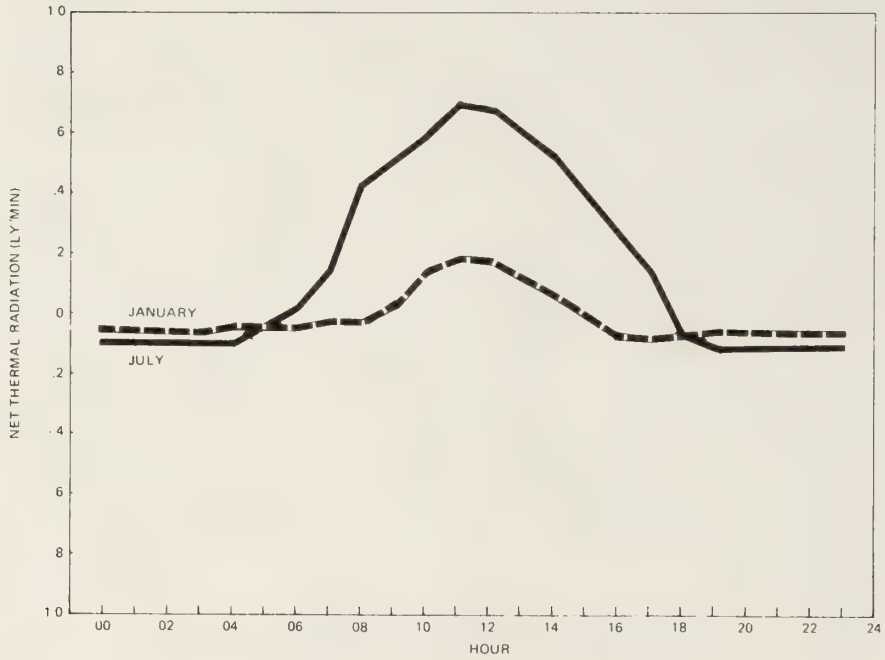

Figure 6-13 DIURNAL VARIATION OF MEAN NET THERMAL RADIATION AT SITE A6 IN JANUARY AND JULY FROM 1975 TO 1980

sunlight, higher solar angle, and less cloudiness. Highest values during the day generally occurred between 1100 and 1200 hours with a peak of 1.25 ly/min in June 1977.

6.3.2 Upper Air Meteorology

Measurements of the upper air meteorology were made by WSRP during the first year (1975) on the tracts. These measurements included rawinsonde balloon launches twice daily on every sixth day, and continuous acoustic sounding at Site A6. The rawinsonde provided records of temperature, relative humidity, and wind from the surface to 500 millibars (about 18,000 feet above mean sea level). A monostatic acoustic sounder displayed atmospheric structure (mixing height, stability, thermal plumes) up to about a kilometer (half-mile) above the surface. Additional bistatic records taken on a less regular basis were used to show atmospheric turbulence between 200 meters (650 ft) and 450 meters (1,500 ft) above ground level.

From January 1975 through January 1976, surface-based inversions attributable to nocturnal cooling of the earth's surface were generally observed in the morning 90 percent of the time, and usually disappeared in the afternoon. The average thickness of the morning inversion changed from about 520 meters (1,700 ft) in winter to 280 meters (910 ft) in spring to 360 meters (1,190 ft) in summer and to 485 meters (1,590 ft) in fall. The strength of the inversion in spring and summer was about 1.5C/100 meters (0.8F per 100 ft). The strength of the inversion in fall and winter was stronger with an average of 1.7C/100 meters (1.0F per 100 ft) and 1.6C/100 meters (0.9F per 100 ft), respectively.

Upper-air inversions were frequently detected. These inversions were associated with anticyclones that are common in fall and winter, and were indicated in 53 percent of all morning soundings and 87 percent of all

afternoon soundings. The average thickness of the morning upper-air inversions was 250 meters (830 ft), with an average strength of 0.7C/100 meters (0.4F per 100 ft). The height of the base of the morning elevated inversions was 165 meters (540 ft) above ground level. The average base of the afternoon elevated inversions was higher at about 930 meters (3,050 ft). The afternoon inversions had an average thickness of 285 meters (940 ft) with an average strength of 0.9C/100 meters (0.5F per 100 ft).

The temperatures measured above the inversions were generally adiabatic and remained almost invariant throughout the day.

Relative humidity in the lower kilometer (half-mile) above the ground was about 65 percent in the morning and about 50 percent in the afternoon, with no significant change from February to April. In July, this value decreased to about 45 percent in the morning and to about 30 percent in the afternoon. In October, it was about 40 percent in the morning and about 30 percent in the afternoon.

In the upper levels, relative humidity was generally slightly higher than the near surface for both the morning and afternoon. For instance, winter morning and afternoon levels increased to around 80 to 70 percent, respectively, and summer levels to around 50 and 40 percent, respectively.

In the first kilometer above the ground, the winds were quite variable from day to day. Above this level, winds were usually stronger and from the west, with an average speed of about 8 m/s (17.9 mph) during the winter and spring quarters and about 4 m/s (8.9 mph) in the summer and fall.

Theodolite soundings were taken by the EPA at this location (A6) every other day from October 1976 through January 1978. In general, this data

compared well with the WRSP data collected in 1975. For example, no mixing height was observed in 79 percent of the WRSP and 81 percent of the EPA morning soundings, and 8 percent of the WRSP and 11 percent of the EPA afternoon soundings. The average morning mixing height from the WRSP soundings was 37 meters compared to 45 meters for the EPA. There was more variability in the afternoon mixing heights, however, with the EPA's numbers generally lower. The average EPA afternoon mixing height was 714 meters and the WRSP was estimated* to be 1,400 meters. Other than the year-to-year climatic differences, this variation could be due to the fact that the EPA soundings were taken earlier (around 2:00 p.m. MST) than the WRSP soundings (taken around 4:00-6:00 p.m. MST) and to the greater accuracy of the rawinsonde versus the theodolite.

Inversions have considerable variation and are site-specific in rugged terrain. The long-term upper air climatology station that is closest to that of Tracts Ua and Ub is at Grand Junction, Colorado. These data were used to assess the normality of the period of upper-air measurement because synoptic-scale air mass characteristics are similar. This assessment was done by comparing the Grand Junction 700-millibar-level data collected in 1975 to 1976 with 10-year averages. Since the short-term data set did not vary significantly from the long-term averages, it was assumed that the measurement period was faily representative. This normalcy was confirmed by the similarity of the EPA mixing height measurements collected during 1976 to 1978.

6.3.3 Diffusivity

When a gaseous pollutant in the form of a plume or puff is released into the atmosphere it is transported by the prevailing wind. As it travels downwind its concentration decreases as its volume increases. Its growth

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*The WRSP soundings were generally reduced to about 3,000 meters. All mixing heights greater than 3,000 meters were assumed to be equal to 3,000 meters; therefore, this average may be somewhat lower than actual. Twenty percent of the WRSP soundings were greater than this value, while 3 percent of the EPA's were.

in the vertical is governed mainly by the atmospheric stability while its growth in the horizontal depends not only upon stability but on mechanical turbulence. Mechanical turbulence is defined as irregular airflow induced by surface roughness. An indicator of mechanical turbulence is the fluctuation of wind direction or sigma theta (σ_θ). Calculations using values of sigma theta in atmospheric dispersion models were made to estimate potential impacts of project pollutant discharges to the atmosphere.

Using σ_θ data from Site A6, the frequency distributions of different diffusion classes are given in Table 6-15. The classification scheme used follows that in the Atomic Energy Safety Guide 1.23 (Ref. 6-6) and appears in Table 6-16.

When the entire year is considered, diffusion classes D and E are most prevalent on the tracts. Data collected at Site A6 shows that diffusion classes vary most with atmospheric conditions during winter. The annual pattern tends toward a stable atmosphere.

A complete dispersion picture must also include the effect of plume rise. The meteorological parameters that greatly influence the height of a plume are atmospheric stability and wind speed. Vertical atmospheric stability can be best defined by ΔT data. In equations derived by Briggs (Ref. 6-7) for calculating plume height, only three atmospheric stability classes are needed.

Figure 6-14 shows the diurnal variation of ΔT collected at Site A6 for 2 months, January (winter) and July (summer). Note that very stable or slightly stable atmospheric conditions prevailed in early morning and evening during July. In the afternoon, neutral or unstable conditions were a general rule. Because of the almost continuous cloudiness throughout the month of January, the development of strong nocturnal

Table 6-15

RELATIVE FREQUENCY DISTRIBUTION OF DIFFUSION CLASSES AT SITE A6 FROM 1976 THROUGH 1980[a]

Season	Diffusion Classes[b]					
	Unstable			Neutral	Slightly Stable	Very Stable
	A	B	C	D	E	F
Winter	1.5	3.9	13.5	37.4	36.6	7.1
Spring	3.0	7.1	13.2	37.1	34.9	4.7
Summer	3.1	7.4	18.5	36.3	30.9	3.8
Fall	3.2	7.7	15.7	30.0	34.5	8.9
Annual	2.7	6.5	15.2	35.2	34.3	6.1

(a) σ_Θ used to define class.
(b) Basis: Atomic Energy Commission, Safety Guides for Water-Cooled Nuclear Power Plants, NRC Regulatory Guide 1.23, 1972.

Table 6-16

CLASSIFICATION OF ATMOSPHERIC DIFFUSION BY σ_Θ

Diffusion Class	Pasquill Categories	σ_Θ[a] (degrees)
Extremely unstable	A	25.0
Moderately unstable	B	20.0
Slightly unstable	C	15.0
Neutral	D	10.0
Slightly stable	E	5.0
Moderately or very stable	F	2.5

(a) Standard deviation of horizontal wind direction fluctuation. The values shown are midpoints for each diffusion classification.

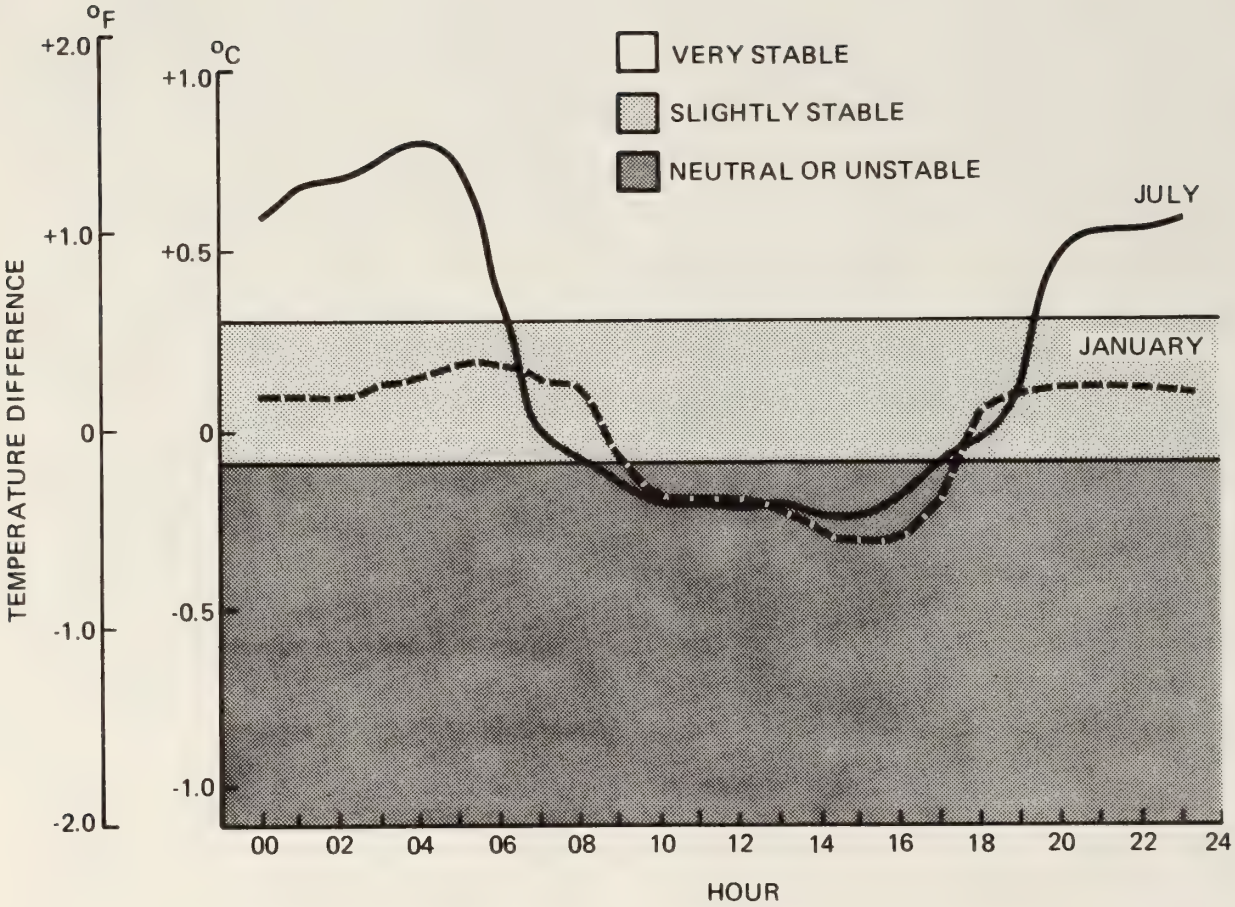

Figure 6-14 DIURNAL VARIATION OF THE MEAN ΔT AT SITE A6 IN JANUARY AND JULY FROM 1977 TO 1980

stability was held to a minimum. Thus, there was only a small diurnal variation in the mean ΔT and the stability was almost alwasy slightly stable or neutral throughout the day.

The frequency distribution of stabilities bases on ΔT appears in Table 6-17. This table shows that very stable conditions occurred less frequently during spring, whereas unstable or neutral activities occurred more often during spring. Total accuracy of the ΔT system used at Site A6 measures ΔT to within ±0.1C/20 meters over the measurement interval.

Joint frequency distributions for wind speed, wind direction, and diffusivity were constructed for Site A6 for 1976 to 1980. The joint frequency distributions were categorized into turbulence intensity (or diffusion) classes as defined by PP. The classification schemes are shown in Table 6-16. This information was used as input into the VALLEY model to compute an annual average of a particular pollutant.

Table 6-17

PERCENT FREQUENCY DISTRIBUTION OF STABILITY BY SEASON
SITE A6 FOR 1977-1980

Season	Unstable or Neutral	Stability Slightly Stable	Very Stable
Winter	46	19	35
Spring	51	24	25
Summer	40	23	37
Fall	44	17	39
All year	45	21	34

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6-2 Progress Report, Environmental Program, 1977, WRSP, Vernal, Utah, July 1978.

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6-3 Quality Assurance Handbook for Air Pollution Measurement Systems, Volume I — Principles, EPA-600/9-76-005, U.S. Environmental Protection Agency, Research Triangle Park, N.C., 1976.

Quality Assurance Handbook For Air Pollution Measurement Systems, Volume II — Ambient Air Specific Methods, EPA-600/4-77-027A, U.S. Environmental Protection Agency, Research Triangle Park, N.C., 1977.

Ambient Monitoring Guidelines for Prevention of Significant Deterioriation (PSD), EPA-450/2-78-019, U.S. Environmental Protection Agency, May 1978.

6-4 Quality Assurance Plan For Air Resources Monitoring, Oil Shale Lease Tracts Ua/Ub AV-QA-8047, AeroVironment Inc., Pasadena, California, February 1981.

6-5 M.W. Chan, and M.I. Smith, "Long-Term Variations in Ozone Measurements in a Remote Area in Northeastern Utah, (AV-TP-81/523, AeroVironment Inc., Pasadena, CA 1981.

6-6 Safety Guides for Water-Cooled Nuclear Power Plants, USAEC, Division of Reactor Standards, Washington, D.C 20545, Atomic Energy Commission, Safety Guide Number 23: On-Site Meteorological Programs, 1972.

6-7 G.A. Briggs, "Diffusion Estimation for Small Emissions," USAEC Report, ATDL-106NOAA, 1974

7. AIR QUALITY IMPACT ASSESSMENT

Section 7

AIR QUALITY IMPACT ASSESSMENT

7.1 INTRODUCTION

The air quality impacts of operating three phases of the project were assessed through diffusion modeling performed by AeroVironment Inc. Table 7-1 lists the total emissions of major criteria pollutants in both pounds per day and tons per year for operation during these phases. These emissions are detailed in Section 5.

Two dispersion models were used to analyze the air quality impacts. Annual average concentrations of particulates, SO_2, and NO_2, and 24-hour averages of particulates and SO_2 were projected using a modified version of the VALLEY model. Three-hour averages of SO_2 and 1- and 8-hour averages of CO were also derived from outputs of this model. Ozone levels were predicted with the REM2 model.

In addition to impacts on the surrounding areas near lease Tracts Ua and Ub, the impacts of particulates and SO_2 on the nearest proposed Class I area (Dinosaur National Monument) were also calculated. Figure 7-1 shows the proximity of Tracts Ua and Ub to a number of existing and proposed Class I areas in the region.

The predicted maximum concentrations of particulates, NO_2, SO_2, CO, and O_3 were compared with applicable national standards and PSD increments during operation. No violations are expected. Phase I impacts were found to be very low. In fact, a slight reduction in ozone concentrations is predicted for Phase I. Phase III impacts were greater and approached Class II increments near tract boundaries for particulates and SO_2. However, analysis of

Table 7-1

ESTIMATED EMISSIONS (AFTER CONTROL)[a] FROM PROJECT OPERATION

lb/day (tons/year)[b]

Pollutant	Phase I	Phase II	Phase III
Particulates	2,048 (285)	5,314 (782)	10,402 (1,515)
SO_2	3,101 (510)	5,193 (853)	7,161 (1,175)
NO_x	7,531 (1,236)	24,948 (4,097)	44,856 (7,366)
HC	1,125 (190)	4,539 (761)	8,766 (1,477)
CO	2,911 (477)	8,786 (1,443)	20,744 (3,407)

(a) Efficiencies and types of control are discussed in Section 5.

(b) Tons/year emissions adjusted for assumed operating time and number of dry days per year (for wind erosion of storage and disposal piles).

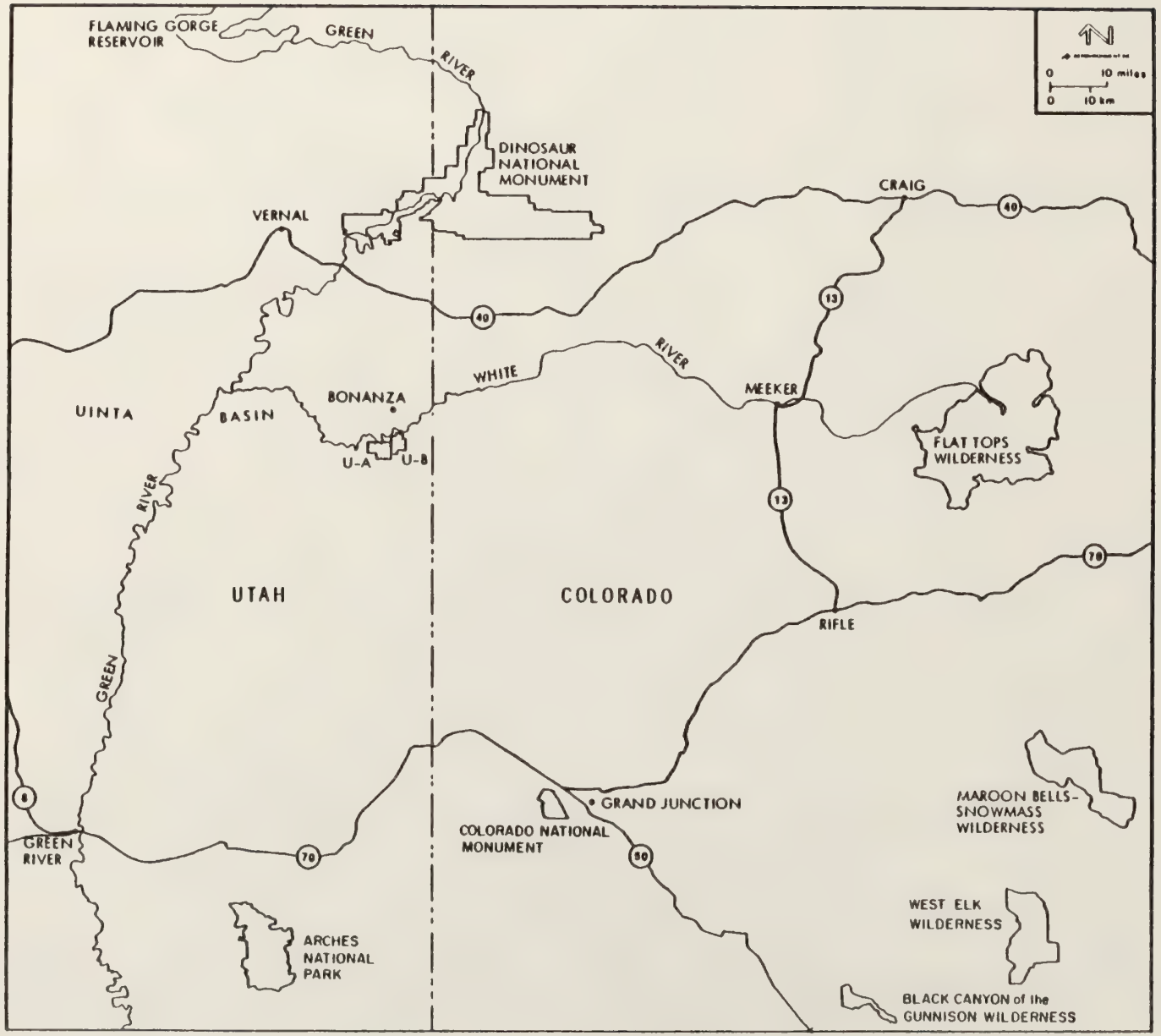


Figure 7-1 EXISTING AND PROPOSED CLASS I AREAS IN THE VICINITY OF THE STUDY AREA

Phase III combined with other permitted projects in the area still demonstrated compliance with the standards.

7.2 DESCRIPTION OF THE MODELING APPROACH

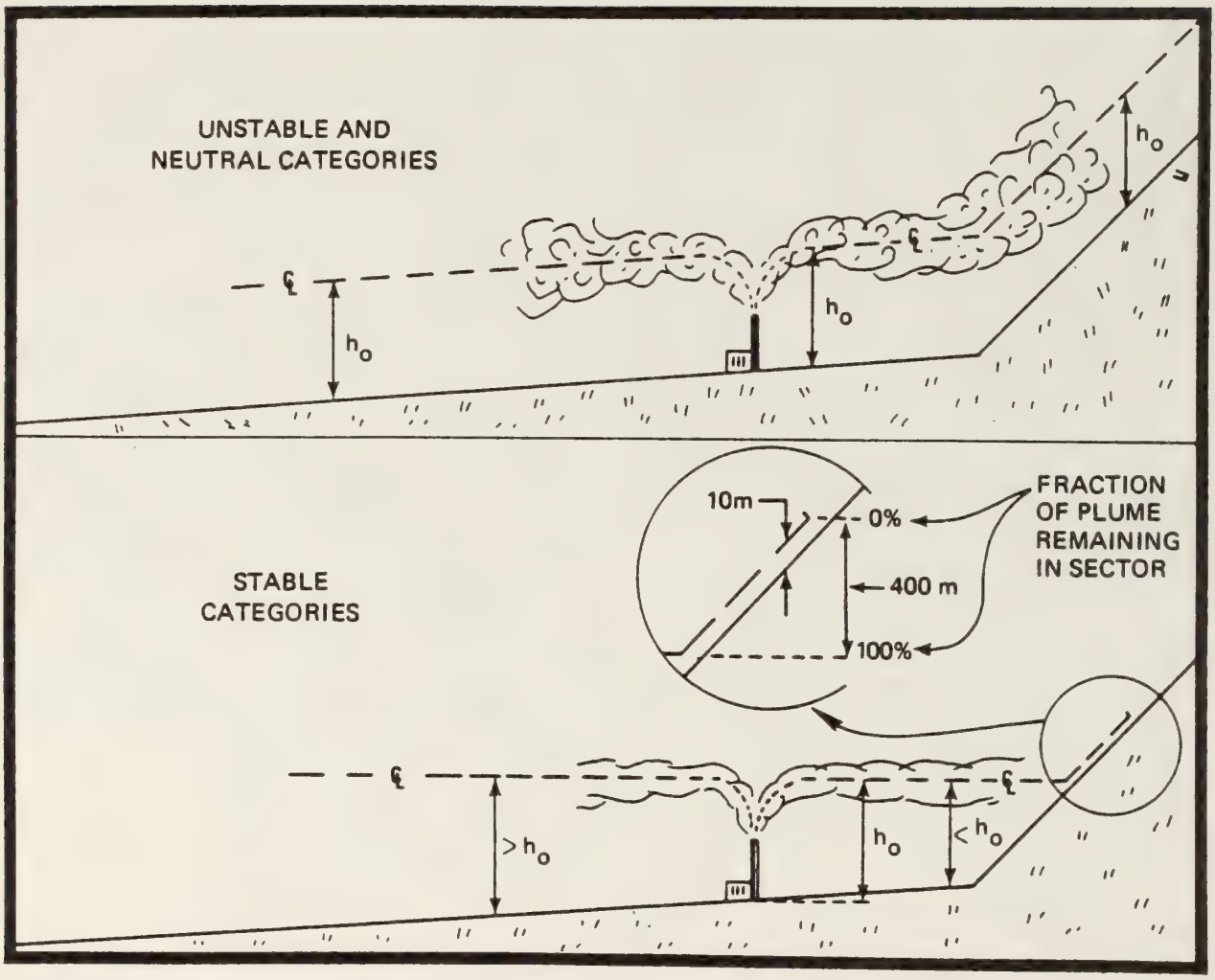
7.2.1 The EPA "VALLEY" Model

VALLEY was used for screening-level estimation of the impacts of Phase I and Phase III emissions for both short- and long-term averages. This model is described in Reference 7-1.

VALLEY is a steady-state Gaussian dispersion model for multiple point and area sources. It includes an algorithm to simulate the effects of complex terrain on ground-level concentrations. In estimating annual-average concentration of atmospheric stability, wind speed, and wind direction. VALLEY also simulates dispersion for 24-hour averages by specifying a single stability/wind speed/wind direction meteorology which the model assumes persists for a maximum of six hours during the 24-hour scenario.

The algorithm to simulate effects of complex terrain is illustrated in Figure 7-2. For stable atmospheric conditions, the model assumes that the plume height above stack base remains constant after final plume rise. Thus as terrain rises, the plume height above terrain decreases. However, the minimum height above terrain is maintained at 10 meters.

For neutral or unstable atmospheric stability conditions, the plume is assumed to follow the terrain at constant height above the ground after final plume rise. This is, in effect, a flat-plane simulation which may slightly underestimate concentrations since plumes may actually impinge on terrain in unstable conditions. However, flow channeling into canyons and valleys is not simulated, which may overestimate impacts on adjacent higher terrain.



NOTE: h_o is the height of the plume rise above ground for the unstable and neutral cases and above stack base for the stable cases. Plumes are shown for flows toward and away from elevated terrain.

Figure 7-2 PLUME HEIGHT IN COMPLEX TERRAIN (AS IN THE VALLEY MODEL)

VALLEY Modifications

The VALLEY terrain algorithm was used as the core of the model developed to assess the impacts of oil shale development on Tracts Ua and Ub. VALLEY is the model recommended for this application by the State of Utah's Bureau of Air Quality (UBAQ) and by the EPA Region VIII permits section. However, the EPA Office of Air Quality Planning and Standards does not recommend models incorporating complex-terrain algorithms which treat cases where terrain extends above release height, which is the case for the WRSP. Therefore, to more accurately assess contaminant dispersion in this situation, VALLEY was modified. These modifications include different diffusion algorithms and plume rise equations and are discussed below.

Refined Treatment of Dispersion Coefficients. Many widely used models, including VALLEY, currently use dispersion algorithms based on the work of Pasquill-Gifford. Based on their work, a set of curves were developed to define the expected dispersion of air pollutants under different stability conditions. However, these curves were developed from a limited data set which included only measurements over nearly flat terrain. Equations were written for these curves which define dispersion in terms of the horizontal and vertical deviations (sigmas) of a Gaussian distribution. Recently, there is increased concern in the scientific community over the extensive use of these equations, especially in complex terrain situations. The American Meteorological Society (Ref. 7-2) has carefully analyzed this problem and has discouraged the use of these equations for elevated sources in complex terrain. Furthermore, it is well-recognized that measured dispersion rates in complex terrain are generally much greater than those deduced by using the Pasquill-Gifford sigmas. Differences between observed and calculated concentrations ranged from a factor of 1.4 in unstable conditions, to about 4 in neutral, and as much as 15 in stable air.

To allow a more realistic simulation of impacts, dispersion coefficients specifically developed for complex terrain applications are used in this

study. These dispersion algorithms are modified versions of formulas suggested by Briggs (Ref. 7-3) for open country conditions. These formulas were rewritten by Mullen et al. (Ref. 7-4) in terms of σ_θ (the standard deviation of the horizontal wind direction within an hour) for each stability class. Measured values of σ_θ form a continuous and directly-related function of the turbulence. Incorporating them in the modified Briggs formulas would better represent the actual turbulence in complex terrain.

Mechanical turbulence generated by the topography of an area is thought to greatly influence the rate at which pollutants diffuse, and accounts for the large differences in concentrations observed between flat and complex terrain. The effect of terrain roughness on turbulence was determined by the Air Force in the LO-LOCAT (low-low level clear air turbulence) program. During that program, nearly 9,000 turbulence spectra were collected over terrain with varying roughness. MacCready (Ref. 7-5), in analyzing the data, developed a relationship between σ_{tr} (the standard deviation of terrain height) and turbulence. This relationship is incorporated into the formulas used in the modified VALLEY model. Because the data base used was very extensive, the relationship developed should be applicable to a wide range of terrain roughness, especially for σ_{tr} ranging from 0 to 300 m (Ref. 7-5) and possibly for larger σ_{tr}. The σ_{tr} is determined objectively from terrain variations in each area to which the formulas are to be applied, so that the equations are applicable to each site.

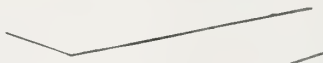
The validity of the dispersion coefficients was confirmed in two separate tracer experiments, one near Bakersfield, California (Ref. 7-4), and one on oil shale Tract Cb in Colorado (Ref. 7-6). The terrain situation on Ua-Ub is similar to that near Bakersfield and Tract Cb. In all these cases, the sources are located in high terrain strongly affected by local drainage flow to a nearby river, with a sharp terrain rise or bluff on the other side. Table 7-2 compares the terrain features for these areas. However, even without these similarities, it is still expected that the dispersion modifications would be applicable at Tracts Ua and Ub due to the site-specific σ_{tr} value. This value is also given in the table.

Table 7-2

COMPARISON OF TERRAIN FEATURES BETWEEN AREAS OF MODIFIED DISPERSION ALGORITHM APPLICATION

Location	Plant[a] Elevation (ft MSL)	Distance To River From Plant (miles)	Elevation of River (ft MSL)	Plant/ River Elevation Difference (ft)	Feature w/ Maximum Elevation Across River (ft MSL)	Plant/ Feature Elevation Difference (ft)	Distance to Feature From Plant (miles)
Ua/Ub Tract	5400	0.7 (White River)	5000	-400	5800 (USLM12)	+400	3.6
Cb Tract	6700	1.5 (Piceance River)	6300	-400	7500 (Collins Gulch) Overlook)	+800	4.0
Kern River Oil Field	800	2.5 (Kern River)	500	-300	900 (Kern Bluff)	+100	4.0

(a) Assumed to be roughly the center of the oil shale processing plant or of the oil field.

	Relative Profile	σ_{tr} (m)
Ua/Ub Tract		192
Cb Tract		260
Kern River Oil Field		100

Refined Treatment of Plume Rise. Most models currently available calculate plume rise based on buoyancy flux alone, with no inclusion of the initial momentum flux. When modeling ambient plumes (cold jets), these routines set the plume rise to zero independent of initial exhaust velocity and ambient wind profile.

In this analysis, cold-jet plume rise formulas based on the treatment of Briggs (Ref. 7-7) were incorporated. The routine calculated plume rise solely through conservation-of-momentum considerations and is used for all ambient jets. Buoyancy-flux based plume rise routines are applied for thermally-elevated releases. This approach is also used in the AVACTA model, which was validated on Tract Cb for a similar application (Ref. 7-8).

7.2.2 The REM2 Model

REM (Reactive Environmental Model) is a Lagrangian model designed to predict photochemical contaminant levels. This model was originally developed by Pacific Environmental Services (PES) with EPA funding for predictions in the Los Angeles Basin. The current version, REM2, has been updated to be easily adaptable to other locations, and contains improvements in the horizontal dispersion simulations (Ref. 7-9).

REM2 is a regional photochemical air quality model which simulates 34 photochemical reactions in a Lagrangian (moving coordinate) frame of reference. The basis of the model is a moving parcel of air, which is bounded by a stable layer (inversion base) above and the ground below. Figure 7-3 illustrates the dynamics of the model. Pollutants enter the moving air parcel from sources located relative to a Cartesian emissions grid, and can diffuse in and out of the moving air parcel by horizontal diffusion.

The location of the base of the moving column at successive moments generates the path or trajectory of the air parcel across the region. The moving parcel of air is assumed to remain vertical and to be well-mixed vertically between ground level and the inversion base. Both the ground terrain level and the inversion base height can be entered as functions of location and

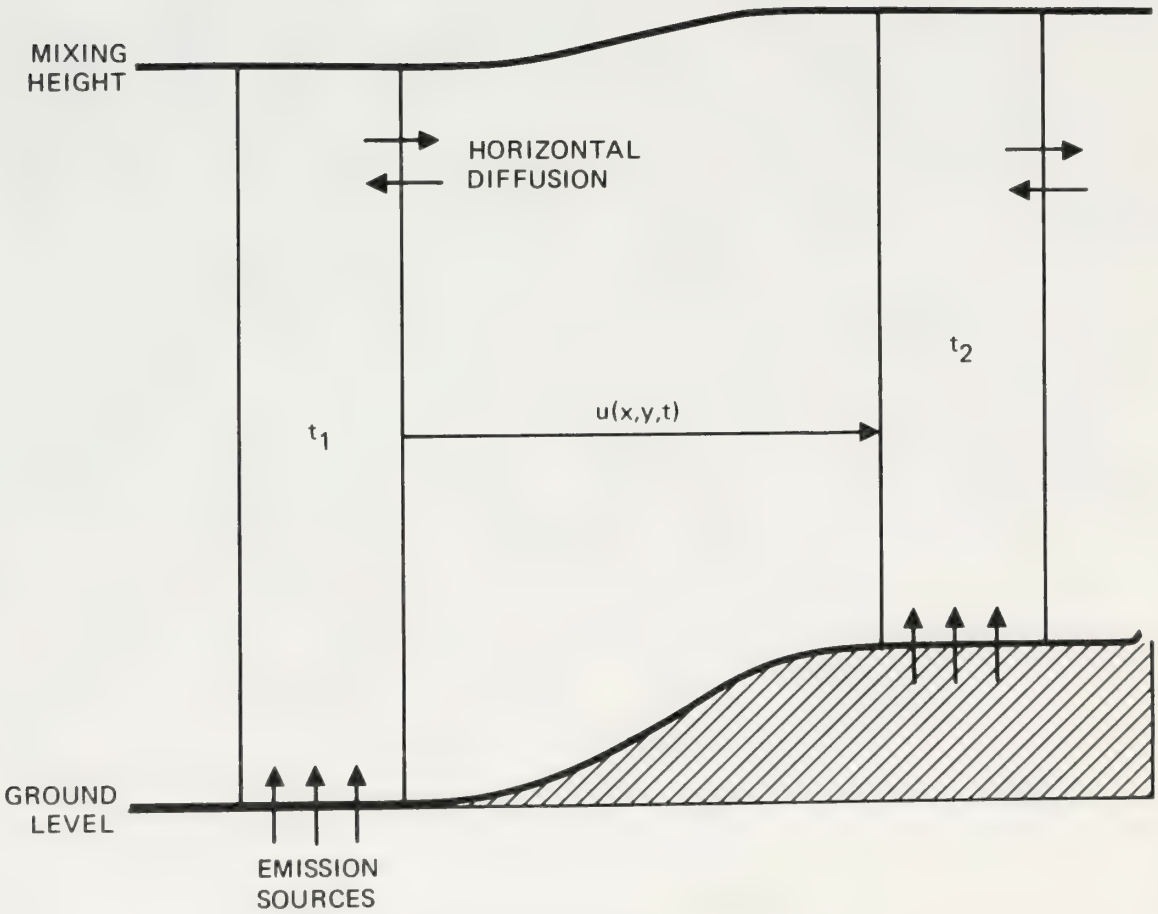


Figure 7-3 REM2 MODEL DYNAMICS

time of day; thus the model can accommodate varying ground terrain and inversion heights.

Because of the Lagrangian formulation which follows an air parcel in a moving-coordinate frame of reference, the basic equation is simply that of conservation of mass in the air parcel for each pollutant of interest. The horizontal diffusion term involves the use of the semi-empirical turbulent diffusion equation or K-theory,

$$\frac{\partial c_i}{\partial t}\bigg|_{\substack{\text{horizontal}\\ \text{diffusion}}} = K_y \frac{\partial^2 c_i}{\partial y^2}$$

where K_y is the horizontal diffusion coefficient and y is the direction perpendicular to the trajectory direction. In program operation, gradients are calculated from concentrations on each side of the air parcel, assumed proportional to the total emissions one grid length away perpendicular to the trajectory direction.

The REM2 computer program is modular with separate subroutines linked to form a complete atmospheric simulation system. Modules now in the system determine the necessary meteorological parameters, the rate of absorption of ultraviolet light by NO_2, emissions due to traffic and area sources, and solution of the conservation-of-mass equations. The ultraviolet absorption module calculates a diurnal ultraviolet irradiance function based on measurement of cloud cover, latitude, and local calendar time. The source emissions module calculates the pollutant inputs to the column of air as it passes over emission sources. Currently, three types of pollutant emissions are considered: nitrogen oxide (NO_x), carbon monoxide (CO), and non-methane hydrocarbons (NMHC). Furthermore, the NMHC emissions are divided into two reactivity classes.

7.3 INPUTS TO THE MODELING ANALYSIS

7.3.1 Primary Pollutants

Primary pollutants are those which are emitted directly by the source. These include particulates, SO_2, NO_x, CO, and HC. Hydrocarbons (HC) are not considered a health hazard by themselves but are analyzed because they lead to the formation of ozone. Therefore, they were modeled only as precursors to ozone formation and are discussed in the next section.

Meteorology

The VALLEY model requires a joint frequency distribution based on wind speed, wind direction, and stability class for long-term analyses. As discussed in Subsection 7.2.1, σ_θ is a good indicator of the level of turbulence in complex terrain and, therefore, stability categories based on σ_θ are more representative of the turbulence intensities in complex terrain than are lapse-rate categories or Pasquill-Gifford categories. Sigma theta has been measured continuously at Site A6 during the monitoring program, and was used to define stability classes for this project. As was discussed in Section 6, wind speed and direction have been measured at four sites for at least the last five years. Site A13 is located at the proposed process area, and its data was considered the most representative for low-level sources. However, since this site only measured wind at the 10-meter level and was located in somewhat of a valley, it was felt that wind measured at Site A6 at the 30-meter level would be more representative of the dispersion characteristics for emissions from sources with significant plume rise. Therefore, two joint frequency distributions were developed, one using A13 winds for modeling fugitive sources such as transfer points and storage piles, and another using A6 30-meter winds for sources with plume rise. These distributions are given in Table 7-3.

For short-term (i.e., 24-hour) analyses, stable conditions (stability category F) with a 2.5-meter-per-second wind speed were used as the worst-case meteorology. These conditions give the highest impacts using the VALLEY model. The worst-case wind direction was determined by running the modified

Table 7-3

JOINT FREQUENCY DISTRIBUTION
(Site A6 30m Wind Speed, Direction and Stability
During 1976 Through 1980)

STABILITY	SPD(MPS)> WIND DIR.	.670	2.540	4.740	6.930	9.610	12.520		TOTAL
A	N	.076	.032	0.000	0.000	0.000	0.000	*	.108
A	NNE	.091	.034	0.000	.002	0.000	0.000	*	.128
A	NE	.074	.039	.005	0.000	0.000	0.000	*	.118
A	ENE	.057	.039	.012	.002	0.000	0.000	*	.111
A	E	.057	.020	.002	0.000	0.000	0.000	*	.079
A	ESE	.044	.032	0.000	0.000	0.000	0.000	*	.076
A	SE	.025	.015	.002	0.000	0.000	0.000	*	.042
A	SSE	.037	.020	0.000	0.000	0.000	0.000	*	.057
A	S	.039	.012	.015	0.000	0.000	0.000	*	.066
A	SSW	.049	.020	.007	0.000	0.000	0.000	*	.076
A	SW	.044	.032	.010	0.000	0.000	0.000	*	.086
A	WSW	.062	.054	.007	0.000	0.000	0.000	*	.123
A	W	.174	.106	.005	0.000	0.000	0.000	*	.285
A	WNW	.221	.152	.022	0.000	0.000	0.000	*	.396
A	NW	.347	.243	.022	0.000	0.000	0.000	*	.612
A	NNW	.207	.106	.012	0.000	0.000	0.000	*	.325
A	TOTL	1.603	.956	.123	.005	0.000	0.000	*	2.687

STABILITY	SPD(MPS)> WIND DIR.	.670	2.540	4.740	6.930	9.610	12.520		TOTAL
B	N	.101	.074	.015	0.000	0.000	0.000	*	.189
B	NNE	.170	.066	.020	0.000	0.000	0.000	*	.256
B	NE	.145	.093	.020	0.000	0.000	0.000	*	.258
B	ENE	.118	.054	.020	0.000	0.000	0.000	*	.192
B	E	.121	.054	.010	0.000	0.000	0.000	*	.184
B	ESE	.084	.027	.002	0.000	0.000	0.000	*	.113
B	SE	.133	.047	.005	0.000	0.000	0.000	*	.184
B	SSE	.091	.044	.017	0.000	0.000	0.000	*	.152
B	S	.115	.059	.032	.005	0.000	0.000	*	.211
B	SSW	.074	.047	.037	.034	.005	0.000	*	.197
B	SW	.101	.074	.032	.025	0.000	0.000	*	.231
B	WSW	.111	.111	.032	.010	0.000	0.000	*	.263
B	W	.270	.334	.069	.007	0.000	0.000	*	.681
B	WNW	.465	.620	.108	.002	0.000	0.000	*	1.195
B	NW	.639	.639	.150	.007	0.000	0.000	*	1.436
B	NNW	.317	.278	.025	0.000	0.000	0.000	*	.620
B	TOTL	3.053	2.620	.593	.091	.005	0.000	*	6.362

STABILITY	SPD(MPS)> WIND DIR.	.670	2.540	4.740	6.930	9.610	12.520		TOTAL
C	N	.182	.111	.037	.002	0.000	0.000	*	.332
C	NNE	.285	.103	.039	.010	0.000	0.000	*	.438
C	NE	.361	.155	.103	.020	0.000	0.000	*	.639
C	ENE	.349	.133	.108	.020	0.000	0.000	*	.610
C	E	.398	.148	.049	.002	0.000	0.000	*	.597
C	ESE	.384	.074	.007	.002	0.000	0.000	*	.467
C	SE	.428	.113	.025	.005	0.000	0.000	*	.570
C	SSE	.339	.209	.047	.025	0.000	0.000	*	.620
C	S	.332	.275	.121	.165	.005	0.000	*	.897
C	SSW	.209	.133	.106	.288	.034	.002	*	.772
C	SW	.248	.182	.145	.305	.039	.002	*	.922
C	WSW	.229	.170	.140	.167	.010	0.000	*	.715
C	W	.558	.563	.310	.157	.002	0.000	*	1.590
C	WNW	.846	1.084	.546	.079	0.000	0.000	*	2.554
C	NW	.836	.934	.440	.039	0.000	0.000	*	2.249
C	NNW	.460	.344	.138	.002	0.000	0.000	*	.944
C	TOTL	6.443	4.730	2.360	1.288	.091	.005	*	14.917

Table 7-3 (Continued)

STABILITY	SPD(MPS)> WIND DIR.	.670	2.540	4.740	6.930	9.610	12.520		TOTAL
D	N	.266	.170	.062	.047	.002	0.000	*	.546
D	NNE	.364	.243	.093	.059	.002	0.000	*	.762
D	NE	.740	.305	.246	.138	.010	0.000	*	1.438
D	ENE	.605	.388	.327	.231	.044	0.000	*	1.595
D	E	.892	.445	.273	.209	.042	0.000	*	1.861
D	ESE	1.040	.386	.088	.012	0.000	0.000	*	1.527
D	SE	1.507	.978	.152	.039	0.000	0.000	*	2.677
D	SSE	.973	1.355	.543	.246	.027	0.000	*	3.144
D	S	.986	1.500	1.168	1.084	.450	.025	*	5.212
D	SSW	.450	.433	.310	.858	.470	.047	*	2.566
D	SW	.428	.356	.283	.661	.293	.012	*	2.033
D	WSW	.457	.298	.290	.447	.113	.002	*	1.608
D	W	.932	.824	.701	.688	.100	.010	*	3.254
D	WNW	.934	.806	.826	.654	.184	.007	*	3.412
D	NW	.696	.664	.553	.438	.044	0.000	*	2.394
D	NNW	.497	.381	.177	.118	.012	.002	*	1.187
D	TOTL	11.765	9.531	6.092	5.929	1.794	.106	*	35.217

STABILITY	SPD(MPS)> WIND DIR.	.670	2.540	4.740	6.930	9.610	12.520		TOTAL
E	N	.128	.079	.064	.034	.005	0.000	*	.310
E	NNE	.194	.145	.088	.081	.015	0.000	*	.524
E	NE	.310	.290	.165	.093	.010	0.000	*	.868
E	ENE	.248	.268	.115	.071	.029	0.000	*	.733
E	E	.450	.317	.211	.207	.079	.005	*	1.269
E	ESE	.561	.258	.049	.015	0.000	0.000	*	.883
E	SE	1.313	1.792	.135	.020	0.000	0.000	*	3.260
E	SSE	1.047	4.464	4.717	.553	.012	0.000	*	10.794
E	S	.474	2.714	4.007	.470	.032	.005	*	7.702
E	SSW	.165	.167	.148	.211	.037	.002	*	.730
E	SW	.130	.133	.152	.044	.007	0.000	*	.467
E	WSW	.209	.121	.071	.042	0.000	0.000	*	.443
E	W	.639	.924	.391	.261	.074	.017	*	2.306
E	WNW	.541	.484	.361	.649	.351	.115	*	2.503
E	NW	.300	.253	.184	.246	.047	.010	*	1.040
E	NNW	.194	.199	.098	.086	.005	0.000	*	.582
E	TOTL	6.903	12.609	10.959	3.083	.703	.155	*	34.411

STABILITY	SPD(MPS)> WIND DIR.	.670	2.540	4.740	6.930	9.610	12.520		TOTAL
F	N	.135	.015	.002	0.000	0.000	0.000	*	.152
F	NNE	.007	.017	.005	0.000	0.000	0.000	*	.030
F	NE	.012	.015	.005	.005	0.000	0.000	*	.037
F	ENE	.015	.017	0.000	0.000	0.000	0.000	*	.032
F	E	.029	.007	0.000	0.000	0.000	0.000	*	.037
F	ESE	.039	.002	0.000	0.000	0.000	0.000	*	.042
F	SE	.088	.174	.034	0.000	0.000	0.000	*	.297
F	SSE	.143	1.448	2.478	.224	0.000	0.000	*	4.292
F	S	.027	.339	.384	.027	0.000	0.000	*	.777
F	SSW	.012	.002	0.000	0.000	0.000	0.000	*	.015
F	SW	.015	0.000	0.000	0.000	0.000	0.000	*	.015
F	WSW	.020	.007	0.000	0.000	0.000	0.000	*	.027
F	W	.160	.209	.017	0.000	0.000	0.000	*	.386
F	WNW	.111	.074	.007	.002	0.000	0.000	*	.194
F	NW	.029	.005	0.000	0.000	0.000	0.000	*	.034
F	NNW	.022	.017	0.000	0.000	0.000	0.000	*	.039
F	TOTL	.865	2.350	2.933	.258	0.000	0.000	*	6.406

Table 7-3 (Continued)

(Site A13 10m Wind Speed and Direction and
Site A6 Stability During 1976 Through 1980)

STABILITY	SPD(MPS)> WIND DIR.	.670	2.540	4.740	6.930	9.610	12.520		TOTAL
A	N	.107	.053	.006	0.000	0.000	0.000	*	.166
A	NNE	.107	.041	.006	0.000	0.000	0.000	*	.154
A	NE	.091	.050	.009	.003	0.000	0.000	*	.154
A	ENE	.066	.019	0.000	.003	0.000	0.000	*	.088
A	E	.056	.016	.003	0.000	0.000	0.000	*	.075
A	ESE	.069	.025	0.000	0.000	0.000	0.000	*	.094
A	SE	.091	.022	0.000	0.000	0.000	0.000	*	.113
A	SSE	.066	.019	.003	0.000	0.000	0.000	*	.088
A	S	.110	.025	.009	.006	0.000	0.000	*	.150
A	SSW	.066	.019	.012	0.000	0.000	0.000	*	.097
A	SW	.063	.047	.016	.003	0.000	0.000	*	.129
A	WSW	.125	.050	.012	0.000	0.000	0.000	*	.188
A	W	.298	.110	.019	.006	0.000	0.000	*	.433
A	WNW	.304	.194	.031	0.000	0.000	0.000	*	.530
A	NW	.282	.110	.019	0.000	0.000	0.000	*	.411
A	NNW	.204	.060	.016	.003	0.000	0.000	*	.282
A	TOTL	2.103	.859	.163	.025	0.000	0.000	*	3.150

STABILITY	SPD(MPS)> WIND DIR.	.670	2.540	4.740	6.930	9.610	12.520		TOTAL
B	N	.263	.107	.009	0.000	0.000	0.000	*	.379
B	NNE	.213	.088	.006	0.000	0.000	0.000	*	.307
B	NE	.163	.069	.016	0.000	0.000	0.000	*	.248
B	ENE	.113	.063	.006	0.000	0.000	0.000	*	.182
B	E	.135	.053	.003	0.000	0.000	0.000	*	.191
B	ESE	.125	.041	.006	.003	0.000	0.000	*	.176
B	SE	.191	.060	.012	0.000	0.000	0.000	*	.263
B	SSE	.132	.044	.025	0.000	0.000	0.000	*	.201
B	S	.141	.056	.072	.025	0.000	0.000	*	.295
B	SSW	.129	.100	.035	.012	0.000	0.000	*	.276
B	SW	.207	.100	.038	.012	0.000	0.000	*	.357
B	WSW	.379	.266	.053	.003	0.000	0.000	*	.702
B	W	.768	.523	.072	0.000	0.000	0.000	*	1.363
B	WNW	.796	.395	.056	.009	0.000	0.000	*	1.257
B	NW	.479	.326	.038	0.000	0.000	0.000	*	.843
B	NNW	.273	.132	.025	0.000	0.000	0.000	*	.429
B	TOTL	4.507	2.423	.473	.066	0.000	0.000	*	7.469

STABILITY	SPD(MPS)> WIND DIR.	.670	2.540	4.740	6.930	9.610	12.520		TOTAL
C	N	.373	.176	.022	.003	0.000	0.000	*	.574
C	NNE	.385	.116	.025	0.000	0.000	0.000	*	.527
C	NE	.367	.176	.053	.006	0.000	0.000	*	.602
C	ENE	.320	.113	.019	.003	0.000	.003	*	.457
C	E	.426	.119	.019	.009	0.000	0.000	*	.574
C	ESE	.542	.163	.044	0.000	0.000	0.000	*	.749
C	SE	.614	.201	.069	.003	0.000	0.000	*	.887
C	SSE	.417	.138	.088	.028	0.000	0.000	*	.671
C	S	.432	.172	.257	.135	0.000	.003	*	1.000
C	SSW	.329	.207	.188	.172	0.000	0.000	*	.896
C	SW	.407	.282	.229	.157	.009	0.000	*	1.084
C	WSW	.539	.398	.191	.069	0.000	0.000	*	1.197
C	W	1.357	.943	.395	.044	0.000	0.000	*	2.739
C	WNW	1.197	.878	.210	.022	0.000	0.000	*	2.307
C	NW	.683	.398	.082	.009	0.000	0.000	*	1.172
C	NNW	.401	.166	.035	.003	0.000	0.000	*	.605
C	TOTL	8.791	4.645	1.925	.664	.009	.006	*	16.041

Table 7-3 (Continued)

STABILITY	SPD(MPS)> WIND DIR.	.670	2.540	4.740	6.930	9.610	12.520		TOTAL
D	N	.467	.204	.060	.006	0.000	0.000	*	.736
D	NNE	.627	.182	.053	.019	0.000	0.000	*	.881
D	NE	.683	.304	.260	.047	0.000	0.000	*	1.294
D	ENE	.831	.329	.125	.019	0.000	0.000	*	1.304
D	E	1.363	.401	.069	.009	0.000	0.000	*	1.843
D	ESE	2.047	.683	.154	.056	.006	0.000	*	2.946
D	SE	1.965	.605	.339	.135	0.000	0.000	*	3.043
D	SSE	1.316	.442	.539	.254	.006	0.000	*	2.558
D	S	1.282	.580	.821	.774	.035	0.000	*	3.491
D	SSW	.859	.470	.442	.567	.044	0.000	*	2.382
D	SW	.809	.570	.526	.445	.025	0.000	*	2.376
D	WSW	.793	.530	.639	.282	.012	0.000	*	2.257
D	W	1.586	.987	.862	.339	.025	0.000	*	3.799
D	WNW	1.222	.878	.533	.182	.035	.003	*	2.852
D	NW	.784	.367	.176	.028	.003	0.000	*	1.357
D	NNW	.473	.213	.056	.012	0.000	0.000	*	.755
D	TOTL	17.106	7.744	5.654	3.175	.191	.003	*	33.874

STABILITY	SPD(MPS)> WIND DIR.	.670	2.540	4.740	6.930	9.610	12.520		TOTAL
E	N	.398	.103	.019	.016	0.000	0.000	*	.536
E	NNE	.498	.085	.047	.006	0.000	0.000	*	.636
E	NE	.743	.172	.082	.022	0.000	0.000	*	1.019
E	ENE	.849	.245	.085	.003	0.000	0.000	*	1.181
E	E	1.655	.335	.091	.006	.003	0.000	*	2.090
E	ESE	3.068	1.291	.298	.019	0.000	0.000	*	4.676
E	SE	3.636	1.611	.502	.082	0.000	0.000	*	5.830
E	SSE	2.257	.730	.332	.069	0.000	0.000	*	3.388
E	S	2.269	.655	.429	.176	.003	0.000	*	3.532
E	SSW	1.316	.342	.122	.050	.003	0.000	*	1.833
E	SW	1.050	.248	.060	.012	0.000	0.000	*	1.370
E	WSW	.805	.295	.210	.113	.028	.006	*	1.457
E	W	1.172	.552	.470	.451	.066	0.000	*	2.711
E	WNW	.805	.395	.354	.157	.028	.003	*	1.743
E	NW	.492	.172	.078	.019	.006	0.000	*	.768
E	NNW	.364	.069	.035	.016	0.000	0.000	*	.483
E	TOTL	21.378	7.299	3.213	1.216	.138	.009	*	33.253

STABILITY	SPD(MPS)> WIND DIR.	.670	2.540	4.740	6.930	9.610	12.520		TOTAL
F	N	.044	.003	0.000	0.000	0.000	0.000	*	.047
F	NNE	.075	.009	0.000	0.000	0.000	0.000	*	.085
F	NE	.082	.003	.003	0.000	0.000	0.000	*	.088
F	ENE	.163	0.000	0.000	0.000	0.000	0.000	*	.163
F	E	.266	.016	.003	0.000	0.000	0.000	*	.285
F	ESE	.686	.129	.050	0.000	0.000	0.000	*	.865
F	SE	1.031	.254	.060	.003	0.000	0.000	*	1.348
F	SSE	.758	.125	.025	.006	0.000	0.000	*	.915
F	S	.702	.066	.022	.003	0.000	0.000	*	.793
F	SSW	.505	.019	.006	0.000	0.000	0.000	*	.530
F	SW	.304	.012	0.000	0.000	0.000	0.000	*	.316
F	WSW	.197	.016	.003	0.000	0.000	0.000	*	.216
F	W	.222	.016	0.000	0.000	0.000	0.000	*	.238
F	WNW	.157	.038	0.000	.003	0.000	0.000	*	.197
F	NW	.072	.012	0.000	0.000	0.000	0.000	*	.085
F	NNW	.044	0.000	0.000	0.000	0.000	0.000	*	.044
F	TOTL	5.309	.718	.172	.016	0.000	0.000	*	6.215

VALLEY model for all combinations of wind direction, pollutant, and operational phase, and is the direction with the maximum predicted concentrations off-tract regardless of its frequency of occurrence.

VALLEY also requires an input of the mean afternoon mixing height, which was determined from Holzworth (Ref. 7-10) to be 2,500 meters. Mean ambient temperature and pressure of 281K and 838 mb, respectively, were also used. These values were determined from data collected at Site A6 during the monitoring program.

Source Characteristics and Emission Rates

The emission calculations and locations of the pollutant sources are discussed in detail in Section 5. The inputs needed to model these sources are discussed here.

For each point source with plume rise, the model was supplied with the UTM coordinates of the source location, the elevation in feet above sea level, exhaust temperature, the stack height above base, stack internal diameter volumetric flow rate, and emission rate in g/sec of each pollutant. If the exhaust temperature, the stack height above base, stack internal diameter, momentum flux. Thermal exhausts were treated as buoyant plumes with plume rise calculated as such.

Fugitive emissions from transfer points and storage and disposal piles were modeled assuming ambient releases with no initial plume rise above release height. Transfer points were modeled as point sources with a release height of 7 meters. This height corresponds to an assumed minimum height over which mixing due to general operations and turbulence would occur. This assumption follows UBAQ guidelines. The fine shale storage pile, raw shale stockpile, and processed shale disposal pile were all modeled as area sources. The size of the area depended on the maximum acreage that would be exposed during the averaging time (i.e., either in a given day or year). Emissions due to load in/out, traffic and maintenance, and wind erosion were assumed to be evenly distributed throughout these areas. Base elevations for the

piles were assumed to be the elevation to which the pile is to be filled at planned capacity. Emissions were again assumed to be released from 7 meters above this elevation, due to mixing by the wind and heavy equipment on the pile.

Source Characteristics and Emission Rates

The emission calculations and locations of the pollutant sources are discussed in detail in Section 5. The inputs needed to model these sources are discussed here.

For each point source with plume rise, the model was supplied with the UTM coordinates of the source location, the elevation in feet above sea level, exhaust temperature, the stack height above base, stack internal diameter, volumetric flow rate, and emission rate in g/sec of each pollutant. If the exhaust temperatures were ambient, the plume rise was calculated based on momentum flux. Thermal exhausts were treated as buoyant plumes with plume rise calculated as such.

Fugitive emissions from transfer points and storage and disposal piles were modeled assuming ambient releases with no initial plume rise above release height. Transfer points were modeled as point sources with a release height of 7 meters. This height corresponds to an assumed minimum height over which mixing due to general operations and turbulence would occur. This assumption follows UBAQ guidelines. The fine shale storage pile, raw shale stockpile, and processed shale disposal pile were all modeled as area sources. The size of the area depended on the maximum acreage that would be exposed during the averaging time (i.e., either in a given day or year). Emissions due to load in/out, traffic and maintenance, and wind erosion were assumed to be evenly distributed throughout these areas. Base elevations for the pile are to be filled at planned capacity. Emissions were again assumed to be released from 7 meters above this elevation, due to mixing by the wind and heavy equipment on the pile.

For NO_2 emissions, a 100 percent conversion rate to this form of the NO_x emitted was assumed, an assumption which will lead to an over-prediction of maximum NO_2 impacts.

These characteristics and emission rates for SO_2, particulates, and NO_x are summarized in Tables 7-4, 7-5, and 7-6 for Phases I, II, and III, respectively. Emission rates for CO and HC are given in Table 7-7.

Receptor Grid Layout and Incorporation of Terrain Roughness

The VALLEY model allows input of up to seven receptors at varying distances along each of the 16 radial directions. In order to be sure that maximum ground-level concentrations were found as well as to define the area impacted (to 1 $\mu g/m^3$) by the WRSP, it was necessary to choose a number of distance increments along the radials. It was determined that the highest impacts would occur fairly close to the tracts, so the greatest receptor definition was needed in the first few kilometers. Therefore, four concentric radial receptor grids with 300, 600, 1,000, and 2,400-m radial increments were used. Figure 7-4 shows the receptor locations used in the analysis. Predicted concentrations at the receptors located within the tract areas are not included in the discussion of impacts. Receptor elevations were chosen from a topographic map in accordance with the guidelines recommended by the EPA Office of Air Quality Planning and Standards. This amounted to selecting, for a given receptor, the highest ground elevation found on a 22.5 degree arc centered on the radial at each receptor distance, since VALLEY assumes the predicted concentrations are uniform within these sectors. For each receptor depicted on Figure 7-4, the assumed ground elevation is shown in Table 7-8.

A second effect of rough terrain on diffusion was represented by incorporating the terrain roughness into the dispersion coefficient formulation, as discussed in Subsection 7.2.1. The parameter for terrain roughness, σ_{tr}, is determined by finding the average standard deviation of terrain height when read every 0.5 mile along 7.5-mile segments surrounding the region of interest, as presented in Reference 7-5. The terrain roughness around

Table 7-4

SOURCE INPUTS FOR PHASE I AIR QUALITY ANALYSIS

Source	UTM Coordinates Zone 12 (km E)	UTM Coordinates Zone 12 (km N)	Ground Elevation (ft MSL)	TSP	Emission Rates (g/s) Annual SO_2	Emission Rates (g/s) Annual NO_x	Emission Rates (g/s) Short-Term TSP	Emission Rates (g/s) Short-Term SO_2	Emission Rates (g/s) Short-Term NO_x	Source Height (m)	Stack Diam. (m)	Exhaust Temp. (K)	Exit Vel. (m/s)	Actual Volume Flow (m^3/s)	Area Source Width (m)
Mine Vents	654.44	4420.84	5525	1.401	0.734	11.133	1.559	0.814	12.369	0.00	8.53	A	19.43	111.30	--
Mine Conveyor Feed Bin	654.01	4421.04	5475	0.058			0.063			15.24	0.46	A	16.92	2.78	--
Storage Silo Feed	654.01	4421.16	5475	0.058			0.065			15.24	0.46	A	16.92	2.78	--
Surface Crushing/ Screening	654.03	4421.12	5475	0.305			0.341			15.24	0.76	A	18.28	8.34	--
Conveyor Feed	653.99	4421.10	5475	0.121			0.135			7.00	--	A	--	--	50
Fines Conveyor Transfers	653.99	4421.16	5475	0.052			0.058			7.00	--	A	--	--	--*
	654.03	4421.16	5475	0.052			0.058			7.00	--	A	--	--	--*
	654.02	4421.26	5475	0.052			0.058			7.00	--	A	--	--	--*
Fines Conveyor Discharge	653.48	4421.25	5450	0.052			0.058			7.00	--	A	--	--	--*
Union Retort Feed	654.03	4421.40	5475	0.009			0.011			15.24	0.23	A	13.54	0.56	--
Superior Retort Feed	653.98	4421.51	5450	0.081			0.089			15.24	0.46	A	13.88	2.28	--
Union Retort Discharge	654.10	4421.42	5400	0.006			0.006			7.00	--	A	--	--	--*
Superior Retort Discharge	654.09	4421.50	5400	0.006			0.006			7.00	--	A	--	--	--*
Processed Shale to Bin	654.10	4420.55	5535	0.029			0.033			9.14	--	A	--	--	10
Raw Shale Stockpile	653.96	4420.70	5703	0.535			0.970			7.00	--	A	--	--	135
Fines Stockpile:															
(1) annual	653.30	4421.36	5450	0.423						7.00	--	A	--	--	142
(2) short-term	653.34	4421.42	5450				0.798			7.00	--	A	--	--	142
Processed Shale Disposal															
(1) annual	654.20	4419.45	5850	2.301						7.00	--	A	--	--	417
(2) short-term	654.40	4419.45	5850				3.509			7.00	--	A	--	--	348
Union B Heater	654.20	4421.44	5400	0.575	0.633	6.012	0.625	0.688	6.694	60.96	1.30	422.04	28.56	37.64	--
Hydrogen Plant Furnace	654.41	4421.51	5400	1.007	1.122	10.884	1.124	1.255	12.065	41.15	1.75	438.71	30.57	73.74	--
Boiler and Steam Plant	654.29	4421.83	5340	0.978	10.988	6.415	1.071	12.206	7.130	30.48	1.90	449.82	36.22	102.73	--
Hydrotreater Furnace	654.49	4421.51	5400	0.066	0.604	1.007	0.074	0.677	1.113	30.48	0.53	422.04	12.88	4.76	--
Flare Pilot	655.08	4421.57	5575	0.002	0.029	0.029	0.003	0.029	0.037	30.48	1.30	338.71	0.09	0.12	--
Gas Treatment Plant	655.00	4421.24	5500	0.009	0.547	0.118	0.009	0.620	0.131	30.48	0.53	422.04	8.22	1.84	--

(*) Fugitive release assumed to be a point source without plume rise.
(A) Ambient temperature of 281 K.

Table 7-5

SOURCE INPUTS FOR PHASE II AIR QUALITY ANALYSIS

Source	UTM Coordinates Zone 12 (km E)	UTM Coordinates Zone 12 (km N)	Ground Elevation (ft MSL)	Emission Rates (g/s) Annual TSP	Annual SO_2	Annual NO_x	Short Term TSP	Short Term SO_2	Short Term NO_x	Source Height (m)	Stack Diameter (m)	Exhaust Temp. (K)	Exit Vel. (m/s)	Actual Volme Flow (m^3/s)	Area Source Width (m)
Mine Vents	654.44	4420.85	5525	2.186	1.165	17.532	2.444	1.294	19.474	7.00	8.53	A	29.14	1667.0	--
	655.63	4421.34	5605	2.186	1.165	17.532	2.444	1.294	19.474	7.00	8.53	A	29.14	1667.0	--
Mine Conveyor Surge Bin	654.01	4421.04	5475	0.086			0.105			15.24	0.76	A	9.75	4.45	--
Mine Conveyor Transfer	653.85	4421.49	5350	0.288			0.310			7.00	--	A	--	--	--*
Storage Silo Feeds	654.01	4421.10	5475	0.058			0.066			15.24	0.46	A	16.92	2.78	--
	654.01	4421.14	5475	0.058			0.066			15.24	0.46	A	16.92	2.78	--
Surface Crushing/Screening	654.01	4421.12	5475	0.604			0.683			9.14	0.76	A	18.28	8.34	--
Fines Conveyor Feed	653.99	4421.10	5475	0.178			0.200			7.00	--	A	--	--	50
Fines Conveyor Transfer	653.99	4421.16	5475	0.240			0.266			7.00	--	A	--	--	--*
	654.03	4421.16	5475	0.240			0.266			7.00	--	A	--	--	--*
	654.02	4421.34	5475	0.240			0.266			7.00	--	A	--	--	--*
Tosco Retort Feeds	654.05	4421.18	5475	0.043			0.047			15.24	0.46	A	16.92	2.78	--*
Union Conveyor Feeds	654.03	4421.40	5475	0.025			0.037			7.00	--	A	--	--	10
	654.03	4421.34	5475	0.025			0.037			7.00	--	A	--	--	10
	654.04	4421.29	5475	0.025			0.037			7.00	--	A	--	--	10
	654.04	4421.24	5475	0.025			0.037			7.00	--	A	--	--	10
Union Retort Feed Silos	654.03	4421.40	5475	0.009			0.011			15.24	0.23	A	13.54	0.56	--
	654.03	4421.34	5475	0.009			0.011			15.24	0.23	A	13.54	0.56	--
	654.04	4421.29	5475	0.009			0.011			15.24	0.23	A	13.54	0.56	--
	654.04	4421.24	5475	0.009			0.011			15.24	0.23	A	13.54	0.56	--
Superior Conveyor Feed	653.99	4421.10	5475	0.106			0.121			7.00	--	A	--	--	50
Superior Retort Feed Bins	653.98	4421.51	5450	0.049			0.055			15.24	0.46	A	16.92	2.78	--
	653.98	4421.59	5450	0.049			0.055			15.24	0.46	A	16.92	2.78	--
Superior Retort Feed Silos	653.98	4421.51	5450	0.032			0.034			15.24	0.38	A	15.60	1.78	--
	653.98	4421.59	5450	0.032			0.034			15.24	0.38	A	15.60	1.78	--
Union Retort Discharge	654.10	4421.42	5400	0.005			0.005			7.00	--	A	--	--	--*
	654.10	4421.35	5420	0.005			0.005			7.00	--	A	--	--	--*
	654.10	4421.30	5420	0.005			0.005			7.00	--	A	--	--	--*
	654.10	4421.25	5420	0.005			0.005			7.00	--	A	--	--	--*
Tosco Retort Discharge	654.10	4421.18	5425	0.003			0.005			7.00	--	A	--	--	--*
Superior Retort Discharge	654.09	4421.51	5400	0.006			0.006			7.00	--	A	--	--	--*
	654.10	4421.61	5375	0.007			0.008			7.00	--	A	--	--	--*
	653.93	4421.73	5320	0.007			0.008			7.00	--	A	--	--	--*

Table 7-5 (Continued)

Source	UTM Coordinates Zone 12 (km E)	UTM Coordinates Zone 12 (km N)	Ground Elevation (ft MSL)	Emission Rates (g/s) Annual TSP	Annual SO_2	Annual NO_x	Short-Term TSP	Short-Term SO_2	Short-Term NO_x	Source Height (m)	Stack Diameter (m)	Exhaust Temp. (K)	Exit Vel. (m/s)	Actual Volume Flow (m^3/s)	Area Source Width (m)
Processed Shale Transfers	654.10	4420.46	5580	0.115			0.124			7.00	--	A	--	--	--*
	653.96	4420.56	5555	0.115			0.124			7.00	--	A	--	--	--*
	653.24	4420.45	5415	0.115			0.124			7.00	--	A	--	--	--*
Processed Shale Disposal:															
(1) annual	653.51	4418.68	5850	3.193						7.00	--	A	--	--	694
short-term	654.17	4418.68	5850				5.723			7.00	--	A	--	--	348
Raw Shale Stockpile	653.92	4420.55	5703	0.990			1.538			7.00	--	A	--	--	188
Union B Heaters	654.20	4421.44	5400	0.532	1.294	6.012	0.593	1.436	6.684	60.96	1.30	422.04	28.43	37.47	--
	654.20	4421.37	5420	0.532	1.294	6.012	0.593	1.436	6.684	60.96	1.30	422.04	28.43	37.47	--
	654.20	4421.32	5420	0.532	1.294	6.012	0.593	1.436	6.684	60.96	1.30	422.04	28.43	37.47	--
	654.20	4421.26	5420	0.532	1.294	6.012	0.593	1.436	6.684	60.96	1.30	422.04	28.43	37.47	--
Tosco Ball Heaters and Lift Pipes	654.17	4421.18	5425	2.560	4.401	6.558	2.830	4.883	7.304	76.20	2.90	327.59	12.89	84.86	--
Tosco Elutriators and Moisturizers	654.15	4421.18	5425	0.777			0.845			76.20	1.83	347.34	13.86	36.40	--
Hydrogen Plants	654.41	4421.51	5400	0.662	1.064	10.758	1.113	1.166	11.945	41.15	1.75	438.71	27.08	65.32	--
	654.41	4421.38	5440	1.870	0.949	19.618	2.074	1.061	21.816	57.30	1.75	438.71	30.57	73.74	--
Power Plant Boilers	654.29	4421.83	5340	0.978	2.186	6.415	1.071	2.442	7.130	76.20	1.90	366.48	29.51	83.70	--
	654.19	4421.83	5340	1.841	4.171	12.225	2.037	4.647	13.583	76.20	3.02	366.48	21.97	157.11	--
Hydrotreater Furnaces	654.49	4421.51	5400	0.037	0.575	0.920	0.068	0.630	1.034	30.48	0.69	422.04	12.88	4.76	--
	654.52	4421.34	5400	0.106	1.036	1.668	0.121	1.134	1.864	30.48	0.91	422.04	12.45	8.18	--
Flare Pilots	655.08	4421.57	5575	0.001	0.019	0.029	0.002	0.021	0.034	30.48	1.30	378.71	0.09	0.12	--
	655.08	4421.60	5575	0.001	0.019	0.029	0.002	0.021	0.034	30.48	1.30	378.71	0.09	0.12	--
Gas Treatment Plant	655.00	4421.24	5500	0.008	0.547	0.118	0.008	0.620	0.131	30.48	0.53	422.04	8.22	1.84	--
	654.97	4421.27	5500	0.025	2.071	0.403	0.027	2.310	0.431	30.48	0.99	422.04	9.53	7.34	--

(*) Fugitive release assumed to be a point source without plume rise.
(A) Ambient temperature of 281 K.

Table 7-6

SOURCE INPUTS FOR PHASE III AIR QUALITY ANALYSIS

Source	UTM Coordinates Zone 12 (km E)	UTM Coordinates Zone 12 (km N)	Ground Elevation (ft MSL)	Emission Rates (g/s) Annual TSP	Annual SO_2	Annual NO_x	Short-Term TSP	Short-Term SO_2	Short-Term NO_x	Source Height (m)	Stack Diam. (m)	Exhaust Temp. (K)	Exit Vel. (m/s)	Actual Volume Flow (m^3/s)	Area Source Width (m)
Mine Vents	654.44	4420.85	5525	2.071	1.100	16.534	2.306	1.221	18.372	0.00	8.53	A	27.32	1562.80	--
	655.63	4421.34	5605	2.071	1.100	16.534	2.306	1.221	18.372	0.00	8.53	A	27.32	1562.80	--
	653.29	4420.95	5480	2.071	1.100	16.534	2.306	1.221	18.372	0.00	8.53	A	27.32	1562.80	--
	653.79	4420.33	5505	2.071	1.100	16.534	2.306	1.221	18.372	0.00	8.53	A	27.32	1562.80	--
Mine Conveyor Surge Bin	654.01	4421.04	5475	0.173			0.194			15.24	0.76	A	18.28	8.34	--
Mine Conveyor Transfer	653.85	4421.49	5350	0.633			0.704			7.00	--	A	--	--	--*
Storage Silo Feeds	654.01	4421.10	5475	0.058			0.066			15.24	0.46	A	16.92	2.78	--
	654.01	4421.14	5475	0.058			0.066			15.24	0.46	A	16.92	2.78	--
	654.00	4421.33	5475	0.115			0.131			15.24	0.69	A	15.04	5.56	--
Surface Crushing/ Screening	654.01	4421.12	5475	0.604			0.683			9.14	0.76	A	18.28	8.34	--
	654.00	4421.31	5475	0.604			0.683			9.14	0.76	A	18.28	8.34	--
Fines Conveyor Feeds	653.99	4421.10	5475	0.334			0.373			7.00	--	A	--	--	50
Fines Reclaim Transfer	654.02	4421.34	5475	0.017			0.018			7.00	--	A	--	--	--*
	654.04	4421.35	5475	0.017			0.018			7.00	--	A	--	--	--*
Fines Conveyor Transfer	653.99	4421.16	5475	0.240			0.266			7.00	--	A	--	--	--*
	654.03	4421.16	5475	0.240			0.266			7.00	--	A	--	--	--*
	654.02	4421.34	5475	0.240			0.266			7.00	--	A	--	--	--*
	654.04	4421.35	5475	0.309			0.344			7.00	--	A	--	--	--*
	654.01	4421.16	5475	0.309			0.344			7.00	--	A	--	--	--*
Tosco Retort Feeds	654.05	4421.18	5475	0.043			0.050			15.24	0.46	A	16.92	2.78	--*
	654.05	4421.13	5475	0.043			0.050			15.24	0.46	A	16.92	2.78	--*
Union Conveyor Feeds	654.03	4421.40	5475	0.025			0.037			7.00	--	A	--	--	10
	654.03	4421.34	5475	0.025			0.037			7.00	--	A	--	--	10
	654.04	4421.29	5475	0.025			0.037			7.00	--	A	--	--	10
	654.04	4421.24	5475	0.025			0.037			7.00	--	A	--	--	10
Union Retort Feed Silos	654.03	4421.40	5475	0.009			0.011			15.24	0.23	A	13.54	0.56	--
	654.03	4421.34	5475	0.009			0.011			15.24	0.23	A	13.54	0.56	--
	654.04	4421.29	5475	0.009			0.011			15.24	0.23	A	13.54	0.56	--
	654.04	4421.24	5475	0.009			0.011			15.24	0.23	A	13.54	0.56	--
Superior Conveyor Feeds	653.99	4421.10	5475	0.106			0.121			7.00	--	A	--	--	50
	653.98	4421.29	5475	0.210			0.231			7.00	--	A	--	--	50
Superior Conveyor Transfer	654.03	4421.66	5390	0.210			0.231			7.00	--	A	--	--	--*
Superior Retort Feed Bins	653.98	4421.51	5450	0.049			0.055			15.24	0.46	A	16.92	2.78	--
	653.98	4421.59	5450	0.049			0.055			15.24	0.46	A	16.92	2.78	--
	653.92	4421.66	5417	0.049			0.055			15.24	0.46	A	16.92	2.78	--
	653.86	4421.64	5417	0.049			0.055			15.24	0.46	A	16.92	2.78	--
	653.71	4421.60	5417	0.049			0.055			15.24	0.46	A	16.92	2.78	--
Superior Retort Feed Silos	653.98	4421.51	5450	0.032			0.035			15.24	0.38	A	15.60	1.78	--
	653.98	4421.59	5450	0.032			0.035			15.24	0.38	A	15.60	1.78	--
	653.92	4421.66	5417	0.032			0.035			15.24	0.38	A	15.60	1.78	--
	653.86	4421.64	5417	0.032			0.035			15.24	0.38	A	15.60	1.78	--
	653.71	4421.60	5417	0.032			0.035			15.24	0.38	A	15.60	1.78	--

Table 7-6 (Continued)

Source	UTM Coordinates Zone 12 (km E)	UTM Coordinates Zone 12 (km N)	Ground Elevation (ft MSL)	Emission Rates (g/s) Annual TSP	Annual SO_2	Annual NO_x	Short-Term TSP	Short-Term SO_2	Short-Term NO_x	Source Height (m)	Stack Diam. (m)	Exhaust Temp. (K)	Exit Vel. (m/s)	Actual Volume Flow (m^3/s)	Area Source Width (m)
Union Retort Discharge	654.10	4421.42	5400	0.005			0.005			7.00	--	A	--	--	--*
	654.10	4421.35	5420	0.005			0.005			7.00	--	A	--	--	--*
	654.10	4421.30	5420	0.005			0.005			7.00	--	A	--	--	--*
	654.10	4421.25	5420	0.005			0.005			7.00	--	A	--	--	--*
Tosco Retort Discharge	654.10	4421.18	5425	0.004			0.005			7.00	--	A	--	--	--*
	654.10	4421.13	5425	0.004			0.005			7.00	--	A	--	--	--*
Superior Retort Discharge	654.09	4421.50	5400	0.006			0.006			7.00	--	A	--	--	--*
	654.10	4421.61	5375	0.009			0.011			7.00	--	A	--	--	--*
	653.93	4421.73	5320	0.009			0.011			7.00	--	A	--	--	--*
	653.80	4421.70	5320	0.009			0.011			7.00	--	A	--	--	--*
	653.67	4421.66	5320	0.009			0.011			7.00	--	A	--	--	--*
Processed Shale Transfers	654.10	4420.46	5580	0.211			0.236			7.00	--	A	--	--	--*
	653.96	4420.56	5555	0.211			0.236			7.00	--	A	--	--	--*
	653.24	4420.95	5415	0.211			0.236			7.00	--	A	--	--	--*
Processed Shale Disposal:															
(1) annual or	653.51	4418.68	5850	4.985						7.00	--	A	--	--	1006
(2) short-term	654.17	4418.68	5850				10.201			7.00	--	A	--	--	348
Fines Storage & Reclaim	653.30	4421.36	5450	0.860			1.843			7.00	--	A	--	--	142
Raw Shale Stockpile	653.92	4420.55	5703	1.352			2.037			7.00	--	A	--	--	230
Union B Heaters	654.20	4421.44	5400	0.554	0.194	5.825	0.621	0.217	6.473	60.96	1.30	422.04	28.56	37.64	--
	654.20	4421.37	5420	0.554	0.194	5.825	0.621	0.217	6.473	60.96	1.30	422.04	28.56	37.64	--
	654.20	4421.32	5420	0.554	0.194	5.825	0.621	0.217	6.473	60.96	1.30	422.04	28.56	37.64	--
	654.20	4421.26	5420	0.554	0.194	5.818	0.621	0.217	6.473	60.96	1.30	422.04	28.56	37.64	--
Tosco Ball Heaters and Lift Pipes	654.17	4421.18	5425	2.546	0.604	5.883	2.835	0.669	6.542	76.20	2.90	327.59	12.89	84.86	--
	654.17	4421.13	5425	2.546	0.604	5.883	2.835	0.669	6.542	76.20	2.90	327.59	12.89	84.86	--
Tosco Elutriators and Moisturizers	654.15	4421.18	5425	0.762			0.843			76.20	1.83	347.35	13.86	36.40	--
	654.15	4421.13	5425	0.762			0.843			76.20	1.83	347.35	13.86	36.40	--
Hydrogen Plants	654.41	4421.51	5400	1.007	0.374	10.615	1.129	0.425	11.797	41.15	1.75	438.71	30.57	73.74	--
	654.41	4421.38	5440	1.899	0.633	19.734	2.105	0.709	21.940	57.30	1.75	438.71	27.37	66.02	--
	654.16	4421.97	5300	1.899	0.633	19.734	2.105	0.709	21.940	76.20	1.75	438.71	27.44	66.19	--
Power Plant Boilers	654.29	4421.83	5340	0.978	2.186	6.415	1.071	2.436	7.130	76.20	1.90	366.48	29.51	83.70	--
	654.19	4421.83	5340	1.841	4.171	12.225	2.037	4.646	13.582	76.20	2.59	366.48	29.91	157.11	--
	654.13	4421.83	5340	5.494	12.542	36.647	6.106	13.949	40.714	76.20	4.51	366.48	29.56	472.50	--
Hydrotreater Furnaces	654.49	4421.51	5400	0.060	0.547	0.921	0.068	0.614	1.013	30.48	0.53	422.04	8.22	1.84	--
	654.52	4421.34	5440	0.106	1.007	1.640	0.121	1.108	1.822	30.48	0.91	422.04	9.53	7.34	--
	654.23	4421.92	5300	0.121	1.151	1.870	0.137	1.265	2.074	30.48	0.99	422.04	9.07	5.01	--
Flare Pilots	655.08	4421.57	5575	0.002	0.017	0.029	0.002	0.021	0.033	30.48	1.30	338.71	0.09	0.12	--
	655.08	4421.60	5575	0.002	0.017	0.029	0.002	0.021	0.033	30.48	1.30	338.71	0.09	0.12	--
	654.17	4422.70	5300	0.002	0.017	0.029	0.002	0.021	0.033	30.48	1.30	338.71	0.09	0.12	--
Gas Treatment Plant	655.00	4421.24	5500	0.008	0.547	0.118	0.008	0.620	0.131	30.48	0.53	422.04	8.22	1.84	--
	654.97	4421.27	5500	0.025	2.071	0.374	0.027	2.310	0.425	30.48	0.99	422.04	9.53	7.34	--
	654.94	4421.28	5500	0.021	1.496	0.316	0.024	1.654	0.362	30.48	0.84	422.04	9.07	5.01	--

(*) Fugitive release assumed to be a point source without plume rise.
(A) Ambient temperature of 281 K

Table 7-7

SHORT-TERM EMISSION RATES (g/sec) FOR CO AND HC DURING PHASE I AND PHASE III OPERATION

Sources	Emission Point	Phase I		Phase III	
		CO	HC	CO	HC
Mine vents	1	4.442	0.735	6.330	1.103
	2	—	—	6.330	1.103
	3	—	—	6.330	1.103
	4	—	—	6.330	1.103
Union B retort - recycle gas heater	1	1.003	0.200	1.025	0.205
	2	—	—	1.025	0.205
	3	—	—	1.025	0.205
	4	—	—	1.025	0.205
Hydrogen plant - reformer furnace	1	1.806	0.357	1.864	0.373
	2	—	—	3.476	0.693
	3	—	—	3.476	0.693
Boiler and power plant	1	7.938	0.478	7.938	0.478
	2	—	—	15.083	0.919
	3	—	—	45.250	2.762
Hydrotreater - reactor feed furnace	1	0.084	0.015	0.074	0.013
	2	—	—	0.137	0.026
	3	—	—	0.152	0.026
Flare pilot	1	0.003	0.001	0.002	0.001
	2	—	—	0.002	0.001
	3	—	—	0.002	0.001
Gas treatment plant	1	0.009	0.002	0.009	0.002
	2	—	—	0.032	0.006
	3	—	—	0.027	0.005
Tosco ball heaters and lift pipes	1	—	—	0.982	5.318
	2	—	—	0.982	5.318
Crude shale oil storage	1	—	1.260	—	5.633
Synthetic crude product oil storage	1	—	0.583	—	4.940
Recovered oil tanks	1	—	0.063	—	0.289
Diesel fuel tanks	1	—	0.017	—	0.063
Fuel oil tanks	1	—	0.001	—	0.007
Naphtha tank	1	—	0.105	—	0.105
Valves, flanges, pump seals, etc.	1	—	2.090	—	13.125

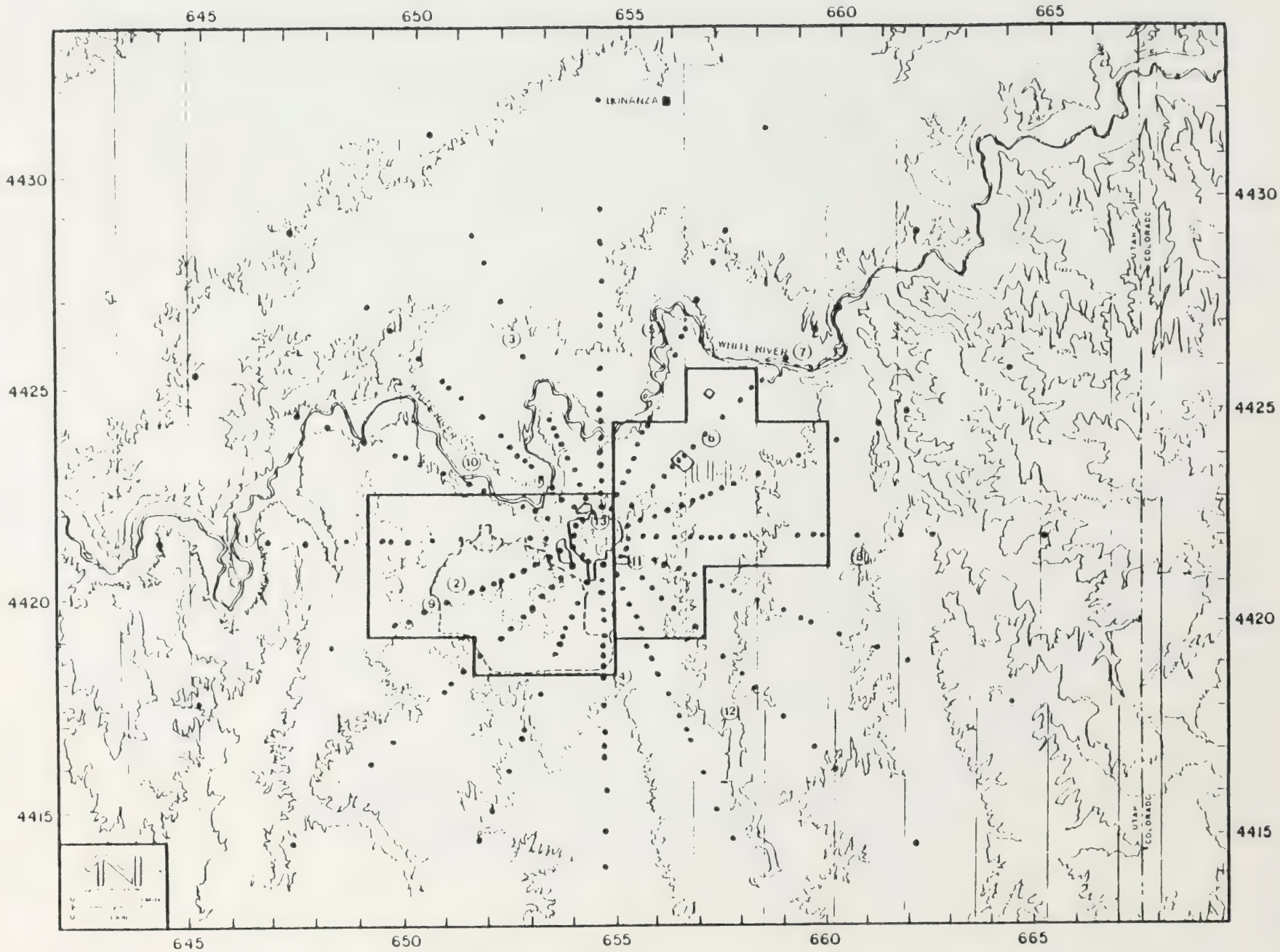


Figure 7-4 RECEPTOR GRID FOR AIR QUALITY IMPACT ANALYSIS

Table 7-8

RECEPTOR ELEVATIONS USED IN THE IMPACT ANALYSIS

Approximate Distance (km)	Elevations (feet MSL) Along Each Directional Radial															
	N*	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW
0.62	5350	5485	5520	5532	--	--	5617	5756	5600	5500	--	5450	5451	5464	5325	5300
0.93	5470	5392	5472	5560	5720	5520	5569	5786	5748	--	5481	5500	--	5390	5281	5300
1.24	5400	5400	5440	5590	5680	5480	5720	5800	5760	5720	5480	5440	5600	5600	5360	5400
1.55	5240	5320	5440	5560	5480	5420	5562	5800	5620	5640	5500	5400	5440	5520	5100	5240
1.86	5200	5230	5400	5410	5400	5450	5520	5640	--	5680	5520	5540	5320	5240	4920	5160
2.17	5120	5200	5320	5412	5400	5400	5480	5680	5800	5720	5640	5460	5520	5200	5085	5160
2.38	5000	5219	5320	5400	5320	5400	5480	5640	5680	5560	5520	5440	5320	5280	5120	5200
2.48	5000	5219	5280	5400	5280	5400	5440	5680	5800	5520	5520	5440	5480	5240	5080	5200
2.88	5120	5160	5320	5280	5320	5280	5480	5720	5720	5680	5516	5480	5334	5200	5160	5120
3.10	5120	5200	5320	5240	5440	5400	5440	5760	5840	5760	5520	5640	5334	5120	5160	5160
3.72	5280	5200	5360	5480	5520	5480	5480	5640	5920	5880	5920	5680	5480	5120	5360	5040
3.84	5280	5200	5290	5440	5520	5560	5420	5720	6000	5920	5960	5680	5541	5120	5320	5337
4.34	5520	5240	5290	5480	5600	5600	5600	5680	6040	5840	5800	5720	5674	5160	5240	5400
4.76	5640	5200	5240	5560	5680	5680	5520	5760	6183	6000	5920	5600	5640	5320	5280	5440
5.76	5640	5314	5411	5608	5825	5800	5655	5720	6160	6000	5712	5591	5772	5623	5603	5720
6.72	5840	5440	5480	5857	5969	5948	5760	5868	6080	5800	5720	5400	5629	5624	5600	5680
7.14	5759	5680	5712	5640	6228	5972	5905	5707	6031	5844	5826	5828	5667	5553	5629	5640
9.52	5600	5688	5993	6380	6266	6679	6037	5800	6159	5986	5640	5986	5634	5587	5455	5484
11.90	5450	5760	5956	6416	6581	6755	6222	6087	6200	5895	6232	5640	5517	5467	5404	5323
14.28	5463	5808	5958	6625	6858	7004	6537	6346	6253	6120	6289	6076	5493	5408	5202	5176
16.66	5433	5727	5849	6473	7000	7227	6601	6346	6130	6138	6385	6054	5658	5275	5009	5202

Note:
(1) Grid center is at 654.43 km east, 4421.49 km north, UTM Zone 12.
(2) Elevations are deleted if the receptor overlies a source during all phases of operation of the facility.
(3) Elevations given represent maximum heights of any terrain feature within a 22.5° sector centered on the radial.

Tracts Ua and Ub was calculated as 192 meters and was included as a parameter in the calculations of σ_z.

Background Concentrations

Annual average concentrations at Site A6 for each of the six years of the baseline monitoring program for each pollutant are presented in Section 6. According to PSD guidelines, the background air quality is best represented by the concentrations observed in the three years previous to the project. For the WRSP site, these values were obtained from the averages of the annual average for 1978 to 1980. Thus the background concentrations for NO_2, SO_2, particulates, and CO are 1.3 $\mu g/m^3$, 1.3 $\mu g/m^3$, 15.7 $\mu g/m^3$, and 0.2 mg/m^3, respectively. These were used along with projected increments in comparisons with the NAAQS.

7.3.2 Secondary Pollutants

Secondary pollutants are those which are not emitted from a source but are formed in the air through the interactions of primary pollutants. The only such pollutant for which there is currently an ambient air quality standard is ozone. Therefore, this is the only secondary pollutant discussed in this report.

Meteorology and Air Parcel Trajectory

In using the REM2 model to assess the impacts of project emissions on photochemical oxidant levels (assumed to be all ozone) in the Uinta Basin, scenarios were chosen to represent adverse situations which could result in high ambient concentrations of ozone. The adverse meteorology consisted of a summer solstice solar altitude profile with no cloud cover, a low wind speed of 1.0 meter-per-second and horizontal diffusion based on a neutrally stable (Pasquill-Gifford Class "D") atmosphere during the day. Calculation of the horizontal diffusivity used in the model is discussed in Reference 7-9.

Hourly values for the meteorological inputs for all REM2 model runs are listed in Table 7-9. The air temperature and relative humidity profiles

Table 7-9

REM2 METEOROLOGICAL INPUTS

Hour (MST)	Wind Speed (m/s)	Air Temp. (C)	Relative Humidity (%)	Mixing Height (m)	Solar Zenith Angle (arc degrees)
0600	1.0	14.0	51.3	625	72.4
0700	1.0	16.3	46.0	1,220	61.2
0800	1.0	19.3	40.3	1,990	47.0
0900	1.0	21.3	37.0	2,505	38.3
1000	1.0	23.3	33.3	3,020	27.5
1100	1.0	24.3	30.7	3,280	19.0
1200	1.0	25.0	27.3	3,460	16.8
1300	1.0	26.0	26.0	3,715	22.9
1400	1.0	26.0	24.3	3,715	32.9
1500	1.0	26.3	24.3	3,790	44.1
1600	1.0	26.3	23.3	3,790	55.6
1700	1.0	26.7	23.3	3,895	67.0

were calculated from hourly averages over the summer months of June, July, and August during the monitoring program at Site A6 on Tract Ub. The hourly mixing height profile was interpolated between the mean summer morning and afternoon mixing height from upper-air soundings at Grand Junction, Colorado (Ref. 7-10). The mean summer morning mixing height of 290 meters was assumed valid at the 0500 MST with a surface air temperature of 12.7C. The mean summer afternoon mixing height of 3,895 meters was assumed to occur at 1700 MST with a daily maximum in surface air temperature of 26.7C. The hourly mixing height for all times between was interpolated from the surface air temperature profile by assuming constant potential temperature throughout the mixed layer.

As a consequence of the Lagrangian nature of REM2, wind direction need not be specified. In the scenarios to be discussed the wind direction was held constant over the entire run. Trajectories were directed over the project sources between 0630 and 0800 MST and followed a straight course for the remainder of the time. The predicted concentrations in these "contaminated" air parcels were compared with results of "clean" air parcel trajectories representing ambient photochemical oxidant behavior under the same meteorology.

Background Concentrations

The 0600 MST background values required for initial conditions were calculated from monitoring program air quality data at Site A6 on Tract Ub. Data from the summers (15 May to 15 August) during 1978, 1979, and 1980 were used for this calculation. The eight days with the highest ozone concentrations (ranging from 130 to 160 $\mu g/m^3$) between 1300 and 1700 MST were examined to provide 0600 MST percursor levels characteristic of adverse ambient ozone production.

The initial ozone concentration used was 90 $\mu g/m^3$, which was the average of the morning O_3 values on the eight highest ozone days during 1978 through 1980. The initial concentrations for the other pollutants were chosen as the threshold limit of the respective monitoring instruments, also corresponding to the initial values of these pollutants on the eight peak ozone

days. These were 66 $\mu g/m^3$ of non-methane hydrocarbons, 0.1 mg/m^3 of carbon monoxide and 5 $\mu g/m^3$ of both nitrogen dioxide and nitric oxide. REM2 requires classification of non-methane hydrocarbons into two reactivity classes. No data were available on the reactivity of the monitored hydrocarbons. A breakdown of 75 percent more reactive and 25 percent less reactive best reproduced the second-highest peak afternoon ozone concentration monitored at Site A6 when used as the initial condition for hydrocarbons in the ambient scenario. The peak ambient REM2 ozone prediction of 126 $\mu g/m^3$ at 1700 MST with these background values is within 13 percent of the monitored peak value of 145 $\mu g/m^3$ also occurring at 1700 MST. A summary of this ambient scenario simulation is given in Section 7.4.2.

Characterisitcs of the Modeled Sources

REM2 treats emissions as area source releases. All NO_x emissions are treated as NO by the model. The two other compounds whose emission rates are used as input are CO and NMHC (non-methane hydrocarbons). The short-term emission rates for Phases I and III for these pollutants were given in Table 7-6. The hydrocarbon emission rates in these tables are for total hydrocarbons including an unknown fraction as methane. In the absence of sufficient data, the entire source release rate quoted in the table is assumed to be non-methane and 100 percent the "more reactive" type.

All sources for each of the modeled phases of project operation were located in a single 2.5 km x 2.5 km grid and the trajectory passing over this source grid was adjusted to reach the grid at about 0630 and to leave the grid at 0800 MST. Table 7-10 presents the grid emission rates for Phases I and III.

7.4 PREDICTED AIR QUALITY IMPACTS

This section presents the results of the modeling discussed in the previous sections. Section 7.4.1 through 7.4.4 discusses the impact of WRSP alone. Section 7.4.5 discusses the cumulative impact of WRSP and neighboring projects. The air quality regulations require that expected pollutant concentrations from the proposed project not exceed certain levels identified

Table 7-10

REM2 EMISSIONS SCENARIOS
(g/s)

Source Grid	NO_x (assumed 100% NO)	HC (assumed 100% reactive)	CO
Phase I	39.54	5.91	15.28
Phase III	235.49	46.02	108.91

for the protection of human health. These levels or standards are given in Table 7-11 for reference in the following section. In addition, federal regulations defined by the Clean Air Act have set incremental levels determined to prevent significant deterioration of the air quality in relatively pristine areas. These levels for the vicinity of the project (Class II area) and for nearby wilderness areas (Class I areas) are given in Table 7-12.

7.4.1 Primary Pollutant Predictions

As stated in Section 7.3, predictions of primary pollutants will address particulates, SO_2, NO_2, and CO air quality impacts.

Annual Average Impacts

The only pollutants for which there are annual standards are particulates, SO_2, and NO_2. Predicted above-background annual average particulate, SO_2, and NO_2 isopleths for Phase I are shown in Figures 7-5 to 7-7. Isopleths for the same pollutants for Phase III are shown in Figures 7-8 through 7-10. Table 7-13 gives the maximum off-tract predicted annual average impacts and the locations for each, including the Phase II operation maxima.

Phase I. The maximum annual particulate increment of 3.8 $\mu g/m^3$ was predicted to occur near the northern junction of Tracts Ua and Ub. This value is well-below the PSD Class II allowable increment of 19 $\mu g/m^3$. With background, this value becomes 19.5 $\mu g/m^3$, less than 33 percent of the NAAQS standard of 60 $\mu g/m^3$.

Table 7-11

FEDERAL AMBIENT AIR QUALITY STANDARDS
(Same as Utah Standards)

Pollutant	Averaging Time	National Standards[a]		
		Primary[b,c]	Secondary[d]	Method of Measurement[e]
Ozone	1 hour	235 $\mu g/m^3$ (0.12 ppm)	Same as primary standards	UV absorbtion
Carbon Monoxide	8 hours	10 mg/m^3 (9 ppm)	Same as primary standards	Nondispersive infrared spectroscopy
	1 hour	40 mg/m^3 (35 ppm)		
Nitrogen Dioxide	Annual Average	100 $\mu g/m^3$ (0.05 ppm)	Same as primary standards	Chemiluminescent
Sulfur Dioxide	Annual Average	80 $\mu g/m^3$ (0.03 ppm)	-	Pararosaniline
	24 hours	365 $\mu g/m^3$ (0.14 ppm)	-	
	3 hours	-	1,300 $\mu g/m^3$ (0.5 ppm)	
Suspended Particulate Matter	Annual geometric mean	75 $\mu g/m^3$	60 $\mu g/m^3$	High-volume sampling
	24 hours	260 $\mu g/m^3$	150 $\mu g/m^3$	
Hydrocarbons[f] (corrected for methane)	3 hours (6-9 a.m.)	160 $\mu g/m^3$ (0.24 ppm)	Same as primary standards	Flame ionization detection using gas chromatography
Lead	Maximum arithmetic mean averaged over a calendar quarter	1.5 $\mu g/m^3$	Same as primary standards	Atomic absorption spectrometry

(a) National standards, other than those based on annual averages or annual geometric means, are not to be exceeded more than once per year.

(b) Concentration expressed first in units in which it was promulgated. Equivalent units given in parentheses are based upon a reference temperature of 25C and a reference pressure of 760 mm of mercury. All measurements of air quality are to be corrected to a reference temperature of 25C and a reference pressure of 760 mm of Hg (1,013.2 millibar); ppm in this table refers to ppm by volume, or micromoles of pollutant per mole of gas.

(c) National Primary Standards: The levels of air quality necessary, with an adequate margin of safety, to protect the public health. Each state must attain the primary standards no later than 3 years after that state's implementation plan is approved by the Environmental Protection Agency (EPA).

(d) National Secondary Standards: The levels of air quality necessary to protect the public welfare from any known or anticipated adverse effects of a pollutant. Each state must attain the secondary standards within a "reasonable time" after its implementation plan is approved by the EPA.

(e) Reference method as described by the EPA. An "equivalent method" of measurement may be used but must have a "consistent relationship to the reference method" to be approved by the EPA.

(f) This is a guideline for control of ozone.

The maximum annual SO_2 increment of 12.0 $\mu g/m^3$ would occur along the northern boundary of Tract Ua about 1 kilometer from the eastern edge. The nearest SO_2 source to the point of maximum impact was the steam plant boiler. This concentration is below the maximum allowable SO_2 annual average PSD increment of 20 $\mu g/m^3$. Including background, the highest SO_2 concentration is predicted to be 13.3 $\mu g/m^3$, less than 18 percent of the federal standard of 80 $\mu g/m^3$.

Table 7-12

LIMITS OF SIGNIFICANT DETERIORATION OF AIR QUALITY

Pollutant	Area Designations[a,b]		
	Class I ($\mu g/m^3$)	Class II ($\mu g/m^3$)	Class III ($\mu g/m^3$)
Particulate Matter:			
Annual geometric mean	5	19	37
24-hour maximum	10	37	75
Sulfur Dioxide:			
Annual arithmetic mean	2	20	40
24-hour maximum	5	91	182
3-hour maximum	25	512	700

(a) Class I applies to areas in which practically any change in air quality is considered significant; Class II applies to areas in which deterioration normally accompanying moderate, well-controlled growth is considered insignificant; and Class III applies to those areas in which deterioration accompanying large industrial growth is considered insignificant.

(b) Areas designated as Class I, Class II, or Class III are limited to the above increases in pollutant concentrations over baseline air quality concentration or to pollutant concentrations no greater than the National Ambient Air Quality Standards, whichever is less.

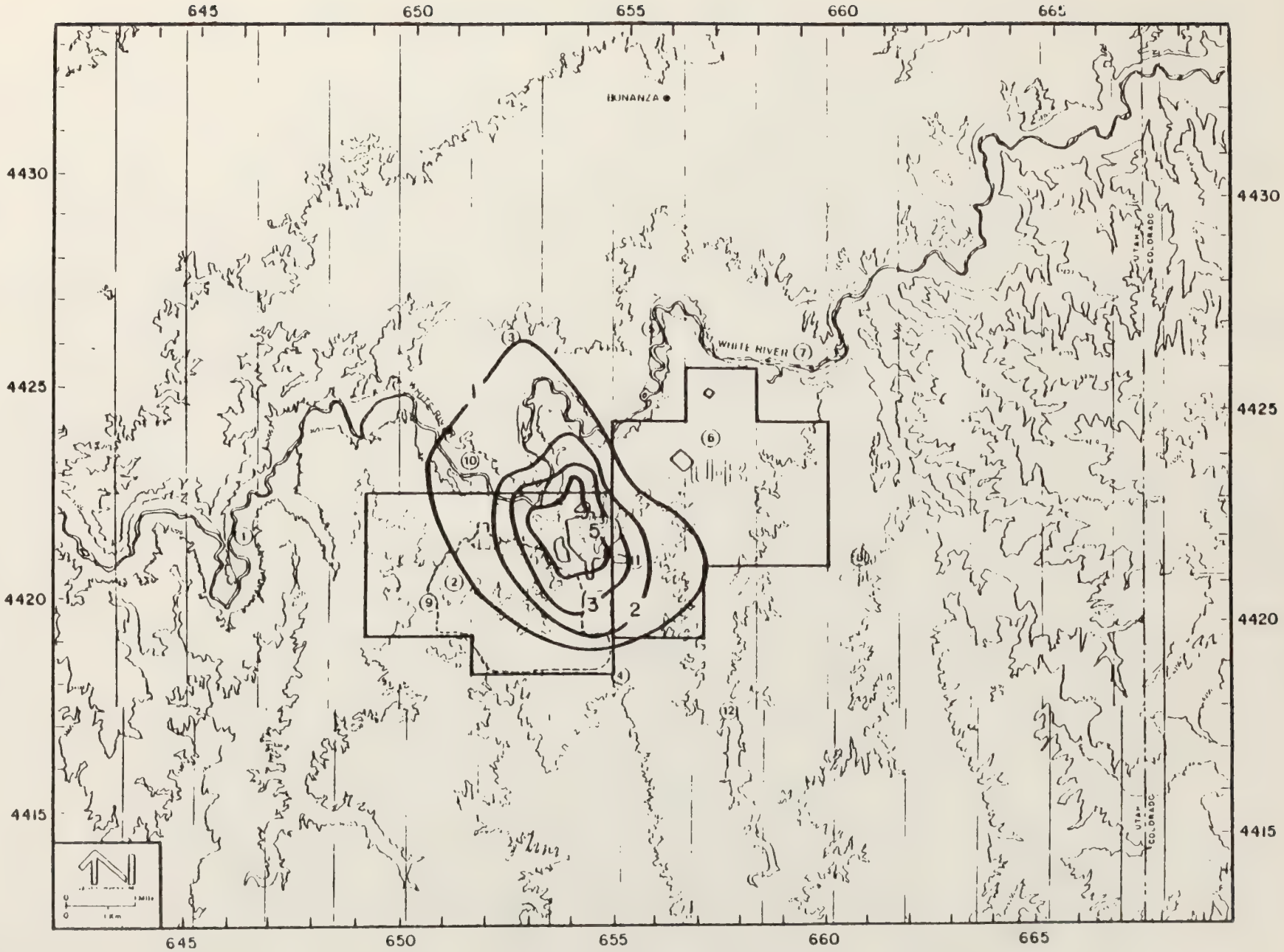


Figure 7-5 CONCENTRATION ISOPLETHS OF PHASE I TSP ANNUAL AVERAGE INCREMENTS ($\mu g/m^3$)

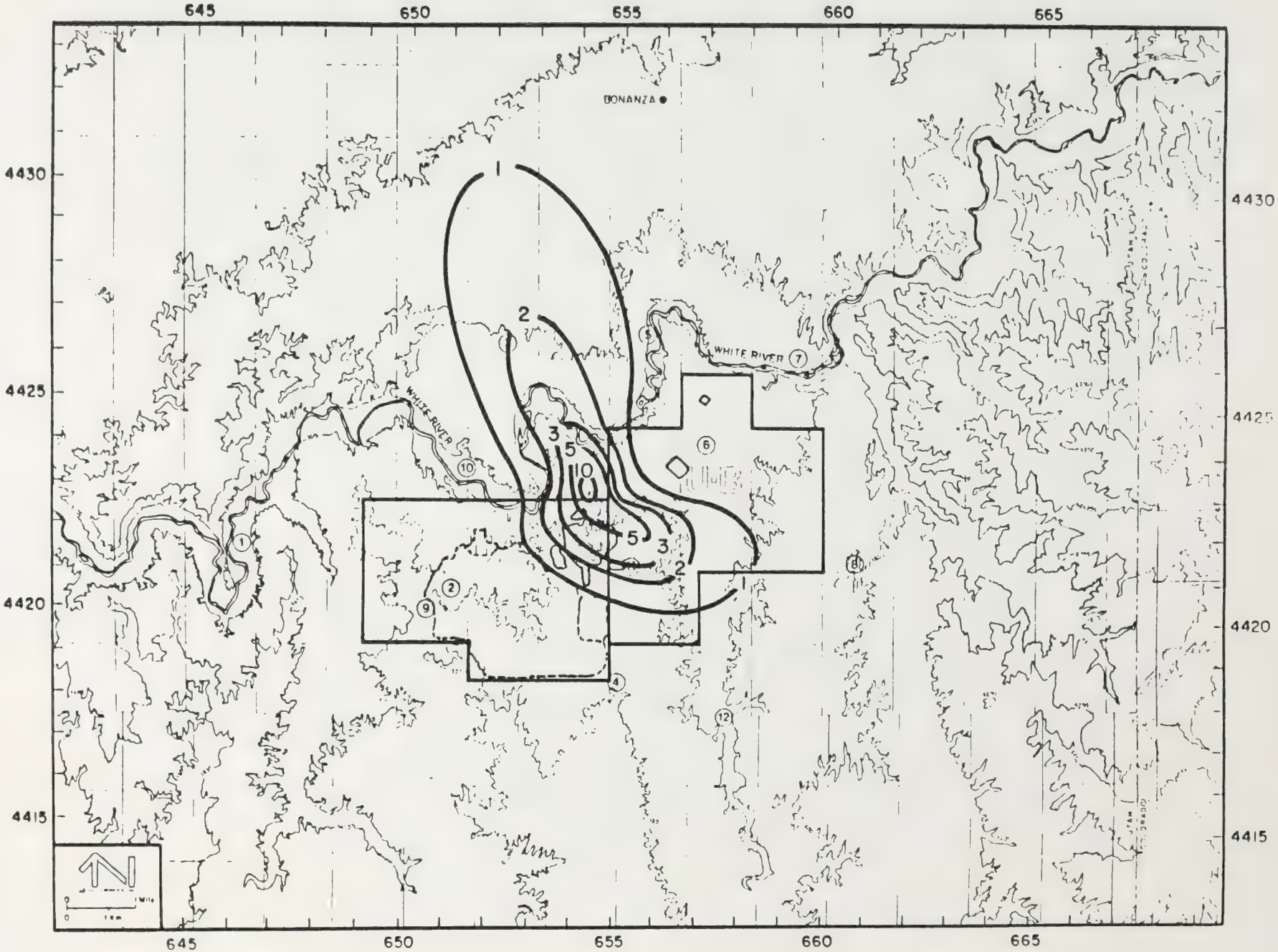


Figure 7-6 CONCENTRATION ISOPLETHS OF PHASE I SO_2 ANNUAL AVERAGE INCREMENTS ($\mu g/m^3$)

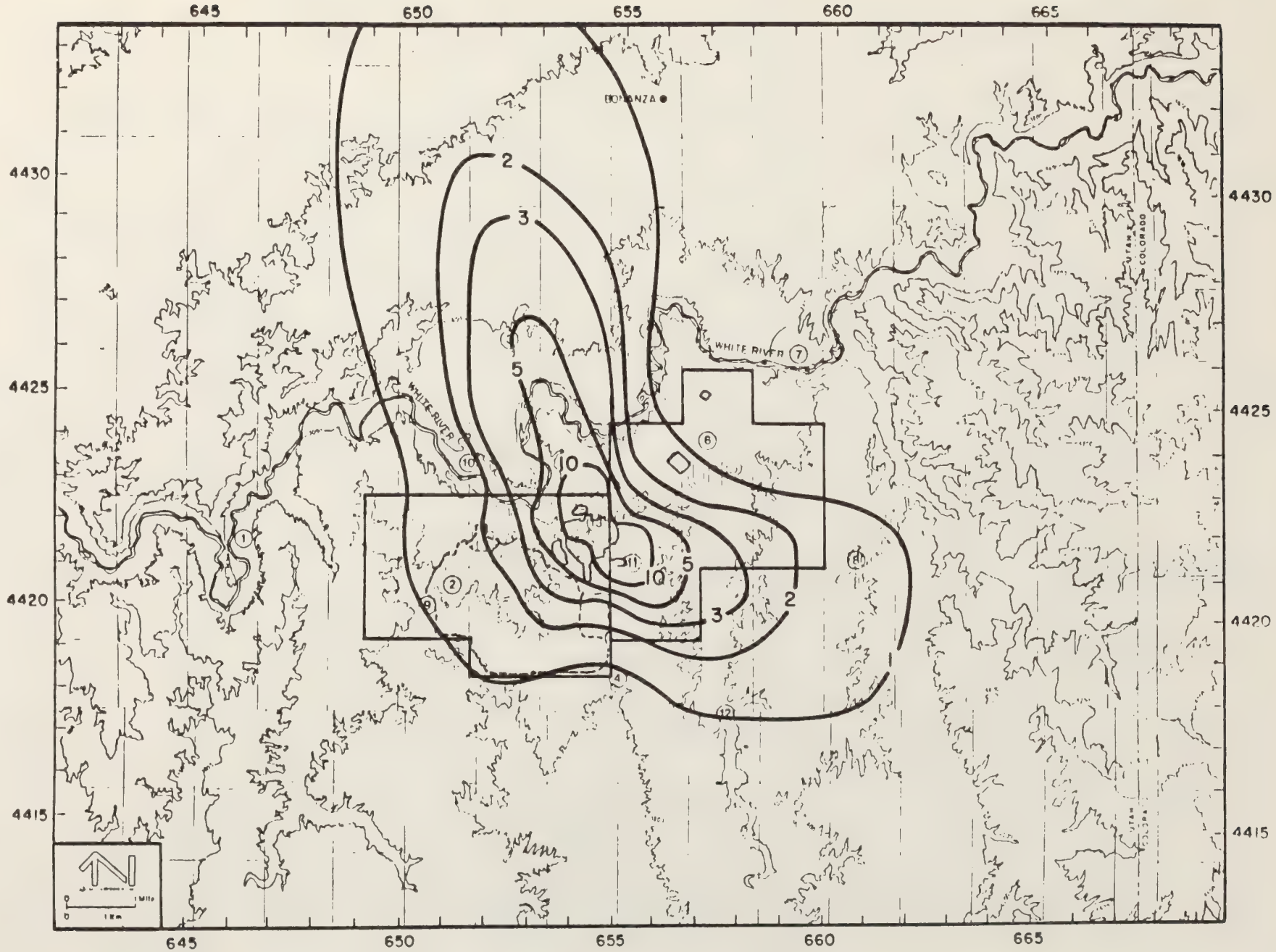


Figure 7-7 CONCENTRATION ISOPLETHS OF PHASE I NO_2 ANNUAL AVERAGE INCREMENTS ($\mu g/m^3$)

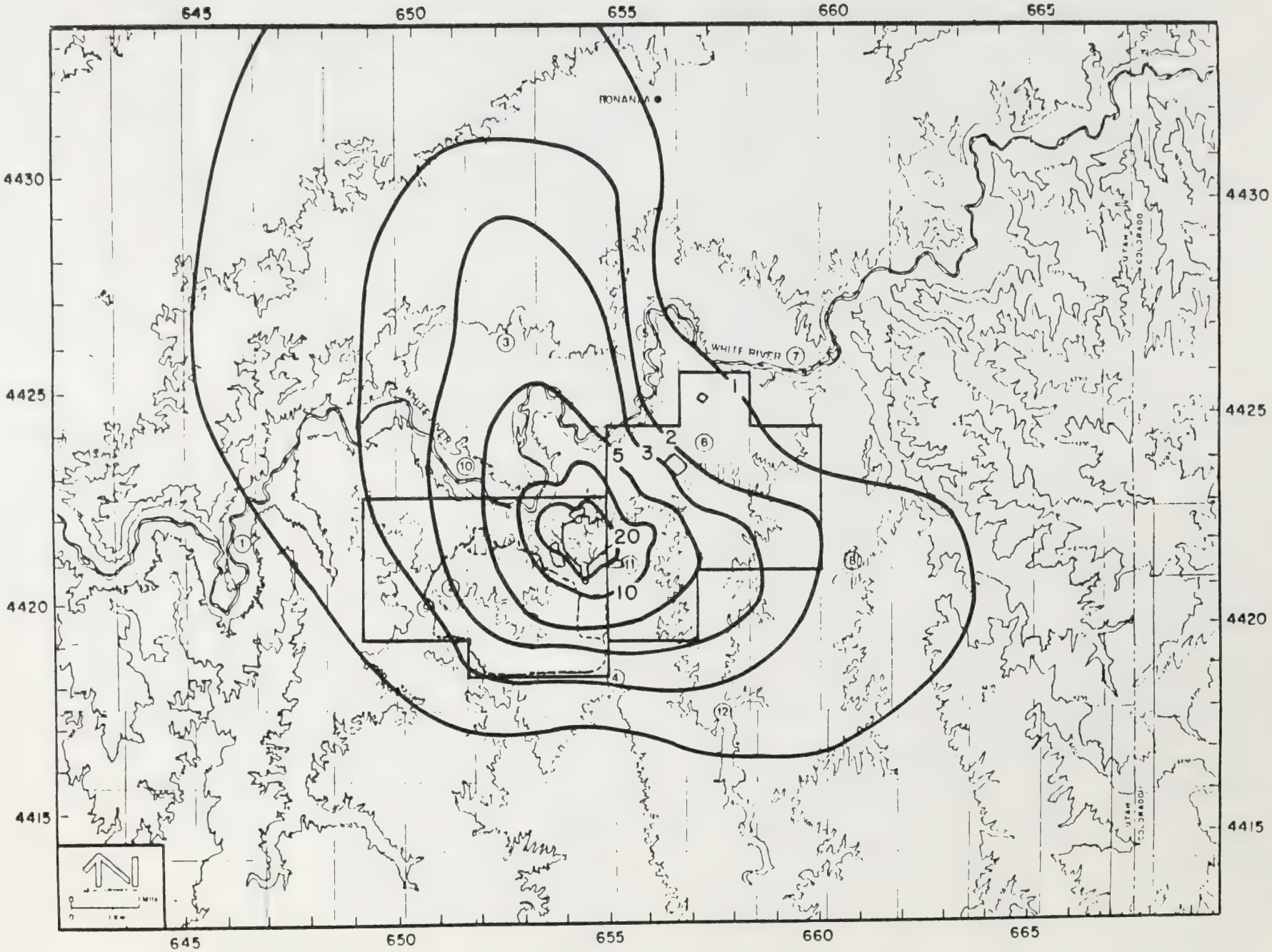


Figure 7-8 CONCENTRATION ISOPLETHS OF PHASE III TSP ANNUAL AVERAGE INCREMENTS ($\mu g/m^3$)

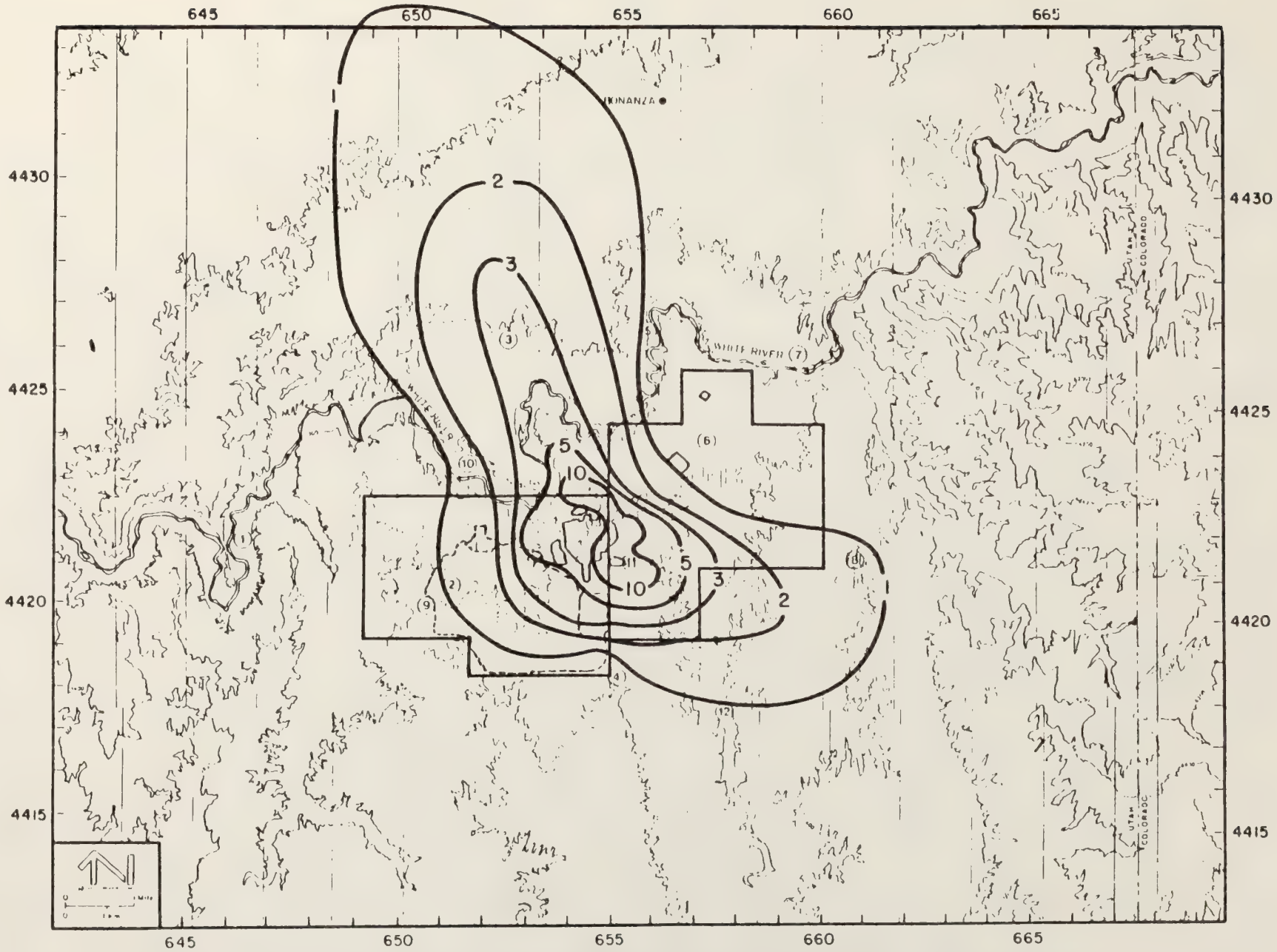


Figure 7-9 CONCENTRATION ISOPLETHS OF PHASE III SO_2 ANNUAL AVERAGE INCREMENTS ($\mu g/m^3$)

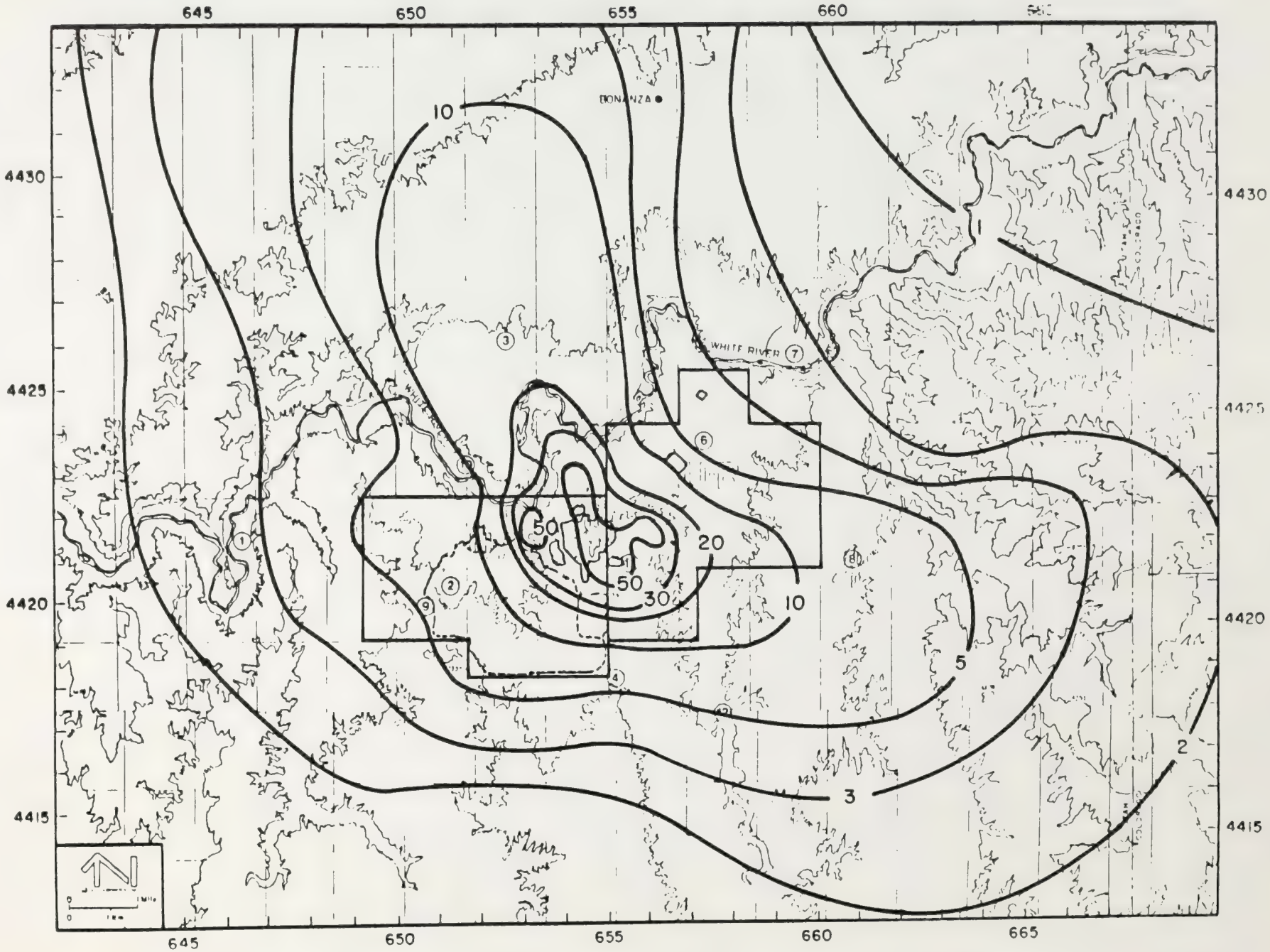


Figure 7-10 CONCENTRATION ISOPLETHS OF PHASE III NO_2 ANNUAL AVERAGE INCREMENTS ($\mu g/m^3$)

Table 7-13

MAXIMUM PREDICTED ANNUAL-AVERAGE OFF-TRACT CONCENTRATIONS, LOCATIONS, AND APPLICABLE STANDARDS

Pollutant	Development (Phase)	Maximum Impact[a] ($\mu g/m^3$)		Receptor Location UTM, Zone 12 (km)	Distance From Nearest Source (m)	Applicable Standards ($\mu g/m^3$)	
		With Background[d]	Increment			NAAQS[b]	PSD (II)[c]
Particulates	I	19.5	3.8	653.9E, 4422.7N	860	60	19
	II	24.3	8.6	653.9E, 4422.7N	570		
	III	32.0	16.3	653.9E, 4422.7N	570		
SO_2	I	13.3	12.0	653.9E, 4422.7N	860	80	20
	II	12.2	10.9	653.9E, 4422.7N	570		
	III	15.0	13.7	653.9E, 4422.7N	570		
NO_2	I	21.8	20.5	653.9E, 4422.7N	860	100	--
	II	47.5	46.2	653.9E, 4422.7N	570		
	III	77.9	76.6	653.9E, 4422.7N	570		

(a) WRSP operation only.

(b) NAAQS are secondary standards for particulates and NO_2 and primary standards for SO_2 and should be compared to "with background" values.

(c) PSD standards are to be compared with the increment expected to accumulate from all PSD sources in the area and cannot be compared directly with the WRSP increment although the cumulative increment is not expected to be much higher. The Class II PSD standard is quoted.

(d) Mean annual average values measured in 1978, 1979, and 1980.

The maximum annual increment of NO_2 was predicted to occur at the same location as the SO_2 maximum. This value is predicted to be 20.5 $\mu g/m^3$. There are currently no PSD incremental standards for NO_2. If background is included, the maximum concentration is predicted at 21.8 $\mu g/m^3$, about 22 percent of the 100 $\mu g/m^3$ annual average NAAQS.

All maximum annual average concentrations are predicted to occur slightly northwest of the process area. This prediction is a result of the very strong influence of the drainage winds flowing down the canyons to the White River Valley. As can be seen from Figures 7-5 through 7-10, this influence is more predominant than the synoptic flows from the west.

Another area where ambient concentrations would be of interest due to public exposure would be the on-tract construction and RV camps shown in Figure 3-2. For Phase I, maximum particulate, SO_2, and NO_2 annual average increments predicted in these areas would be 0.5, 0.5, and 1.1 $\mu g/m^3$, respectively. These values are well below the allowable PSD increment and with background, would also be below the NAAQS.

Phase II. The predicted maximum TSP annual average increment during Phase II operation was 8.6 $\mu g/m^3$. This concentration will occur in the same place as the Phase I TSP maximum and is also below the PSD Class II standard of 19 $\mu g/m^3$. Including background, the predicted maximum is 24.3 $\mu g/m^3$, about 41 percent of the federal secondary standard of 60 $\mu g/m^3$.

The maximum predicted SO_2 increment in Phase II of 10.9 $\mu g/m^3$ is below the Phase I increment. This decrease is due to the addition of a flue gas desulfurization unit which will be put on the steam plants when they are used to produce power starting in Phase II. This impact is predicted to occur at the site of the Phase II TSP maximum and is again below the PSD standard. The predicted maximum concentration of 12.2 $\mu g/m^3$, including background will be less than 16 percent of the 80 $\mu g/m^3$ federal standard.

The maximum predicted NO_2 annual average concentration during Phase II of 47.5 $\mu g/m^3$ (46.2 $\mu g/m^3$ without background) is approximately 50 percent of the NAAQS annual average 100 $\mu g/m^3$ standard. This highest impact is predicted to occur at the sites of both the other Phase II maxima reported above.

In addition, during each of the phases, some construction activities take place for the following phase. The emissions from these activities were not included in the impact predictions for process operation since they are temporary and do not occur throughout the full life cycle of the project. However, to verify that no exceedances of the NAAQS will occur during any part of the project, a scenario was modeled which included construction emissions. These emissions were assumed to consist of only particulates, since the other pollutants are not emitted in significant quantities. This scenario was chosen to correspond to the period with the highest total particulate emissions (from both construction and operation) as identified in Section 5 (Figure 5-3). For this scenario construction emissions of fugitive dust of 146 tons/year (1,140 lbs/day) were modeled as an area source in the process area, with the impacts added to those of the Phase II peak operation impacts. Including background, the peak particulate annual average concentration predicted was 29.9 $\mu g/m^3$. This value is still below the secondary NAAQS of 60 $\mu g/m^3$. Therefore, the project should not cause exceedances of the annual average standard during any of the years of its existence.

Phase III. The predicted maximum particulate annual average increment during Phase III operation is 16.3 $\mu g/m^3$. This concentration would occur in the same place as the Phase I particulate maximum and is also below the PSD Class II standard of 19 $\mu g/m^3$. Including background, the predicted maximum is 32.0 $\mu g/m^3$, 54 percent of the federal secondary standard of 60 $\mu g/m^3$.

The maximum predicted SO_2 increment in Phase III of 13.7 $\mu g/m^3$ is below the annual average Class II increment of 20 $\mu g/m^3$. This impact is also predicted

to occur at the site of the Phase III particulate maximum described above. The predicted maximum concentration of 15.0 $\mu g/m^3$, including background, would be less than 20 percent of the 80 $\mu g/m^3$ federal standard.

The maximum predicted NO_2 annual average concentration of 77.9 $\mu g/m^3$ (76.6 $\mu g/m^3$ with background) is approximately 80 percent of the NAAQS annual average 100 $\mu g/m^3$ standard. This highest impact is predicted to occur at the site of both the other Phase III maxima reported above.

During Phase III, the areas of on-tract habitation (the construction and RV camps) would still receive impacts below applicable standards. The maximum predicted particulate, SO_2, and NO_2 annual average increments in these areas would be 1.9, 0.9, and 5.8 $\mu g/m^3$, respectively.

Predicted Worst-Case Short-Term Impacts

Worst-case meteorology for short-term (24-hour) analyses consisted of a wind speed/stability category set of 2.5 meters-per-second (mps) and stability F. This set has been determined to give maximum concentrations for the VALLEY model. Worst-case wind direction was determined by simulating all 16 primary directions for the three scenarios with the modified VALLEY model and using the direction which produced the highest off-tract concentrations. Table 7-14 gives the highest predicted 24-hour average impacts and indicates the meteorology used for each case. (Wind directions given are the direction from which the wind is blowing.) Particulates, SO_2, and CO are the only pollutants discussed in this section, since there is no national short-term standard for NO_2.

Figures 7-11 through 7-14 depict isopleth plots of worst-case concentrations for the particulate and SO_2 24-hour average model runs in Phases I and III. The receptor grid center for the model runs was located roughly in the center of the process area, chosen because most of the emissions are generated in this area. However, the WRSP includes many air pollution sources spread over

Table 7-14

MAXIMUM PREDICTED OFF-TRACT 24-HOUR AVERAGE CONCENTRATIONS, LOCATIONS, AND APPLICABLE STANDARDS

Pollutant	Development Phase	Maximum Impact[a] ($\mu g/m^3$)		(b) Worst-Case Wind Direction	Receptor Location UTM, Zone 12 (km)	Distance From Nearest Source (m)	Applicable Standards ($\mu g/m^3$)	
		With[e] Background	Increment				NAAQS[c]	PSD(II)[d]
TSP	I	23.4	7.7	N	654.7E,4418.4N	100	150	37
	II	36.9	21.2	N	654.5E,4418.4N	100		
	III	52.5	36.8	N	654.4E,4418.4N	100		
SO_2	I	24.0	22.7	SSE	653.9E,4422.7N	860	365	91
	II	18.9	17.6	NNW	655.3E,4419.2N	1200		
	III	21.9	20.6	NNW	655.4E,4419.2N	1200		

(a) WRSP operation only.

(b) Worst-case meteorology used was F stability and 2.5 m/s wind speed with the tabulated wind directions.

(c) The NAAQS presented are secondary for particulates and primary for SO_2 and are to be compared to the "with background" impacts.

(d) PSD standards are to be compared with the increment expected to accumulate from all PSD sources in the area and cannot be compared directly with the WRSP increment although the cumulative increment is not expected to be much higher. The Class II PSD standard is quoted.

(e) Mean annual average values measured in 1978, 1979, and 1980.

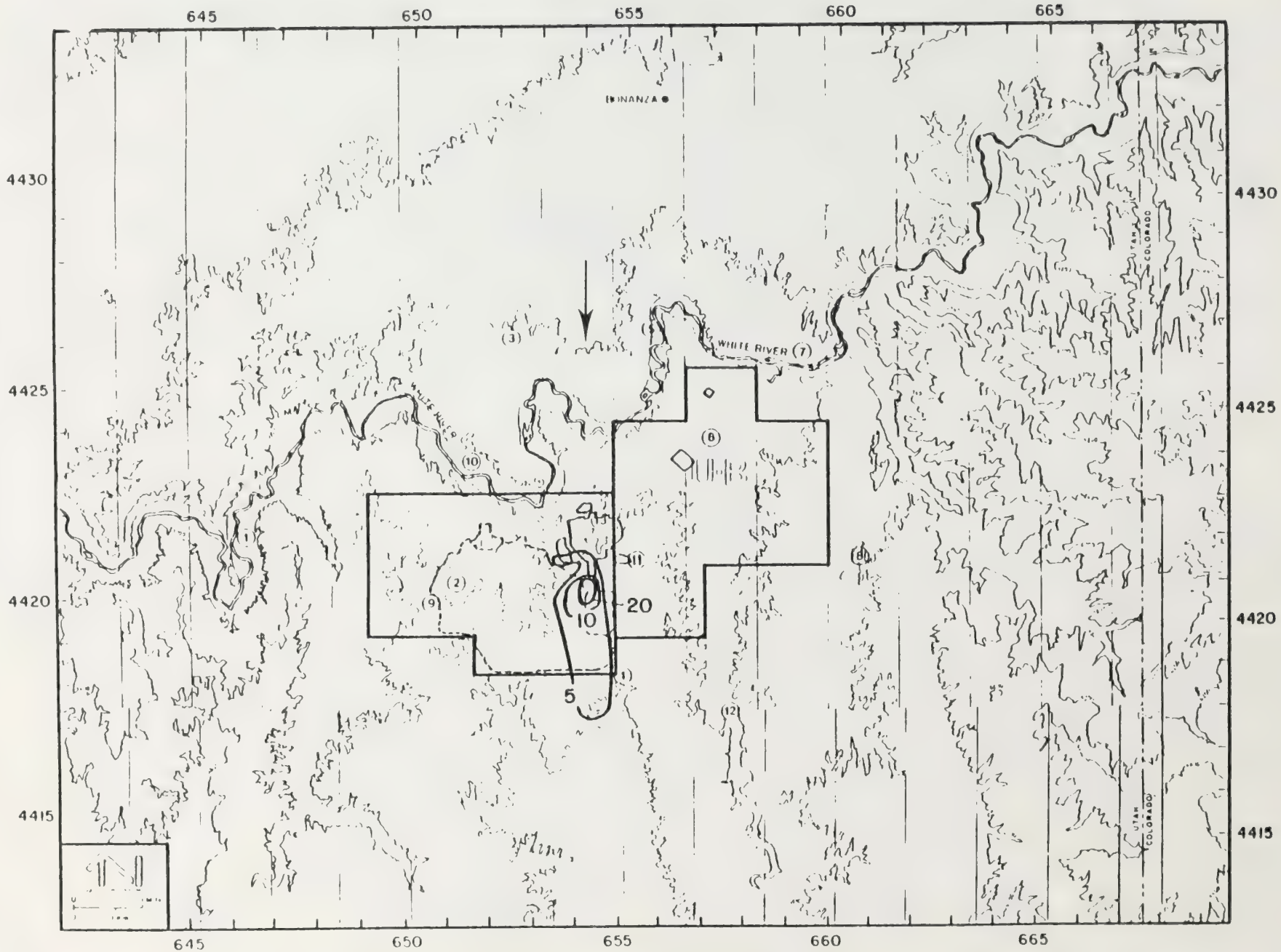


Figure 7-11 CONCENTRATION ISOPLETHS OF WORST-CASE PHASE I TSP 24-HOUR AVERAGE INCREMENTS ($\mu g/m^3$). ARROW DENOTES WIND DIRECTION.

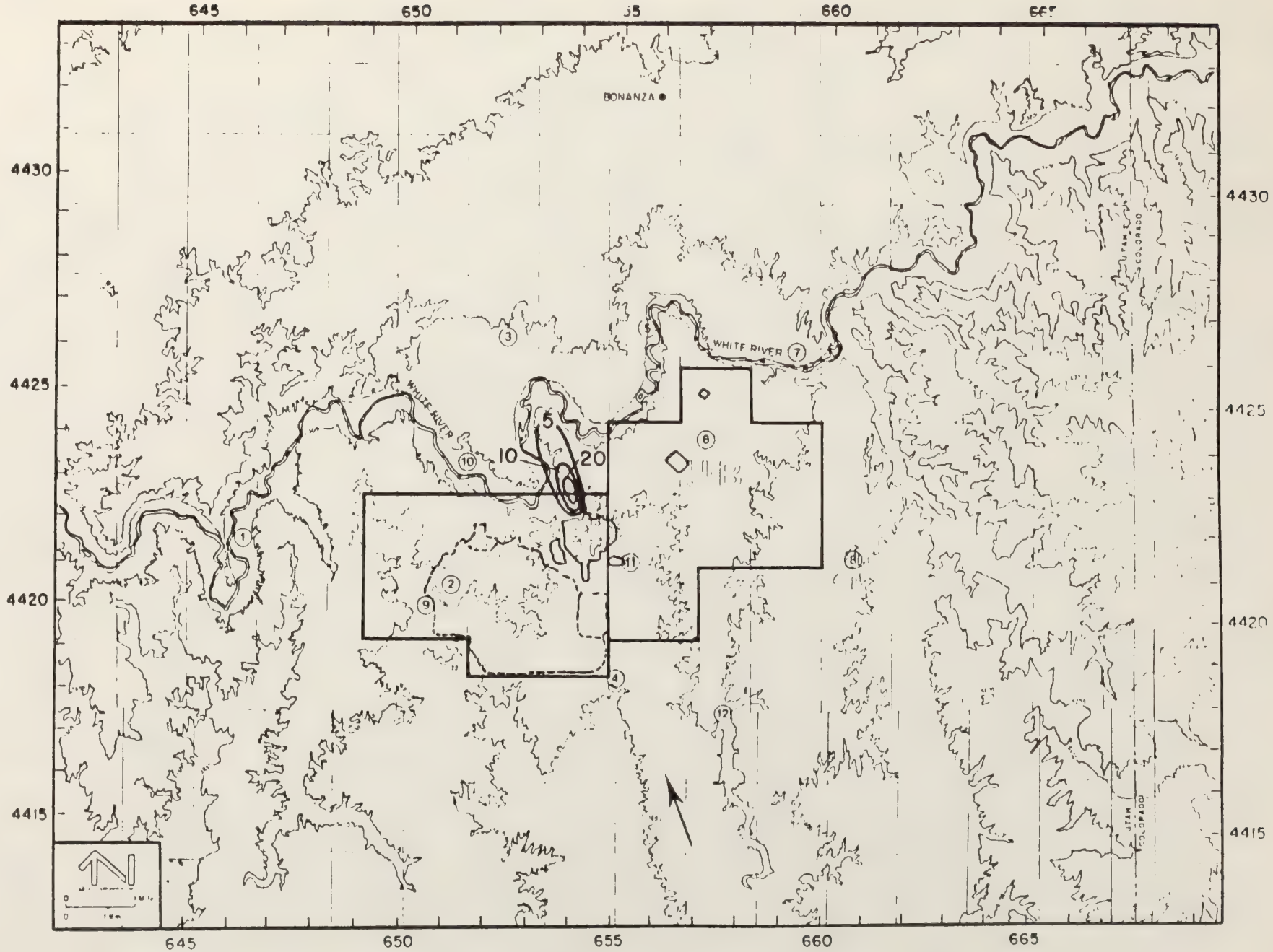


Figure 7-12 CONCENTRATION ISOPLETHS OF WORST-CASE PHASE I SO_2 24-HOUR AVERAGE INCREMENTS ($\mu g/m^3$). ARROW DENOTES WIND DIRECTION.

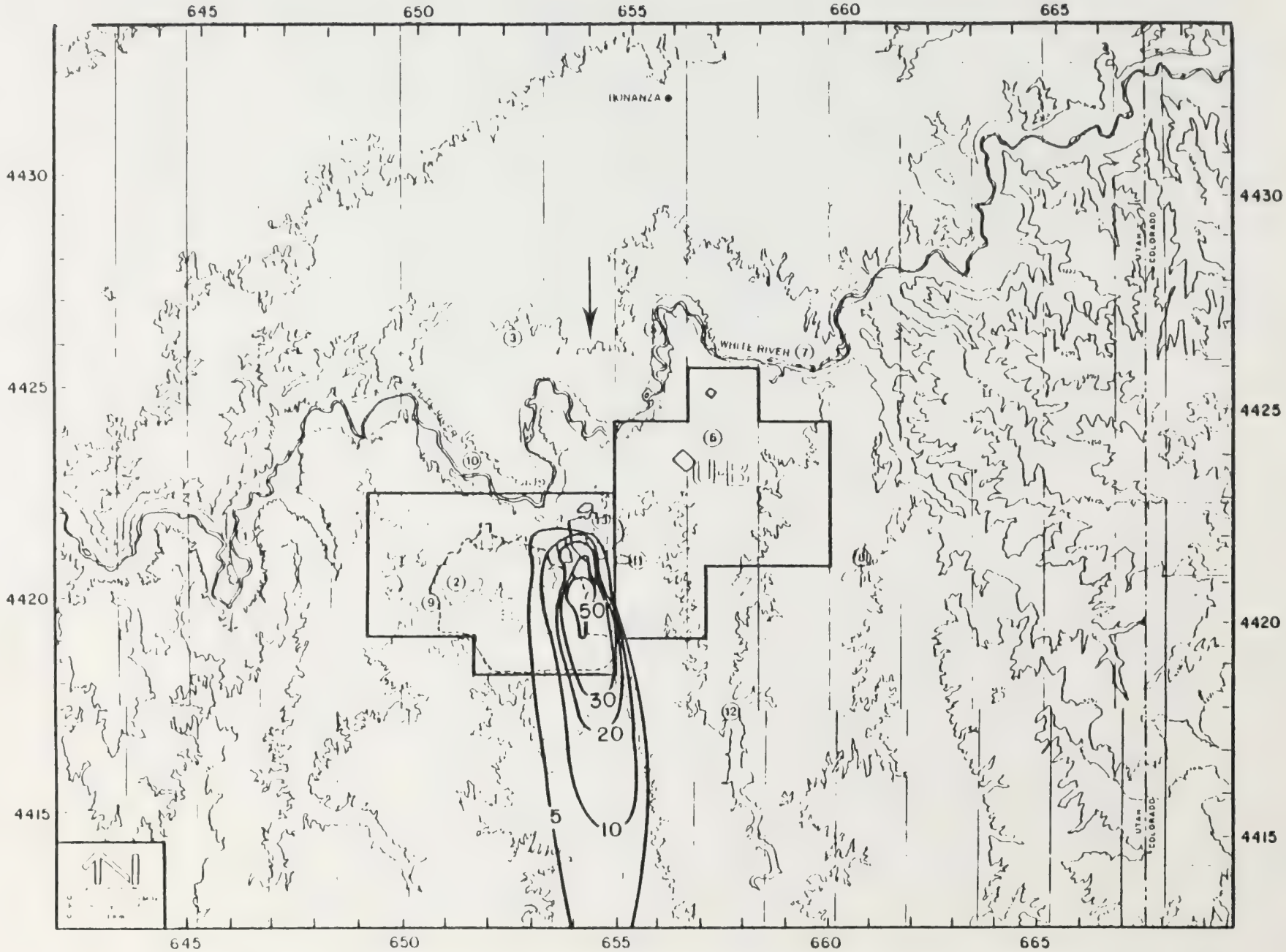


Figure 7-13 CONCENTRATION ISOPLETHS OF WORST-CASE PHASE III TSP 24-HOUR AVERAGE INCREMENTS ($\mu g/m^3$). ARROW DENOTES WIND DIRECTION.

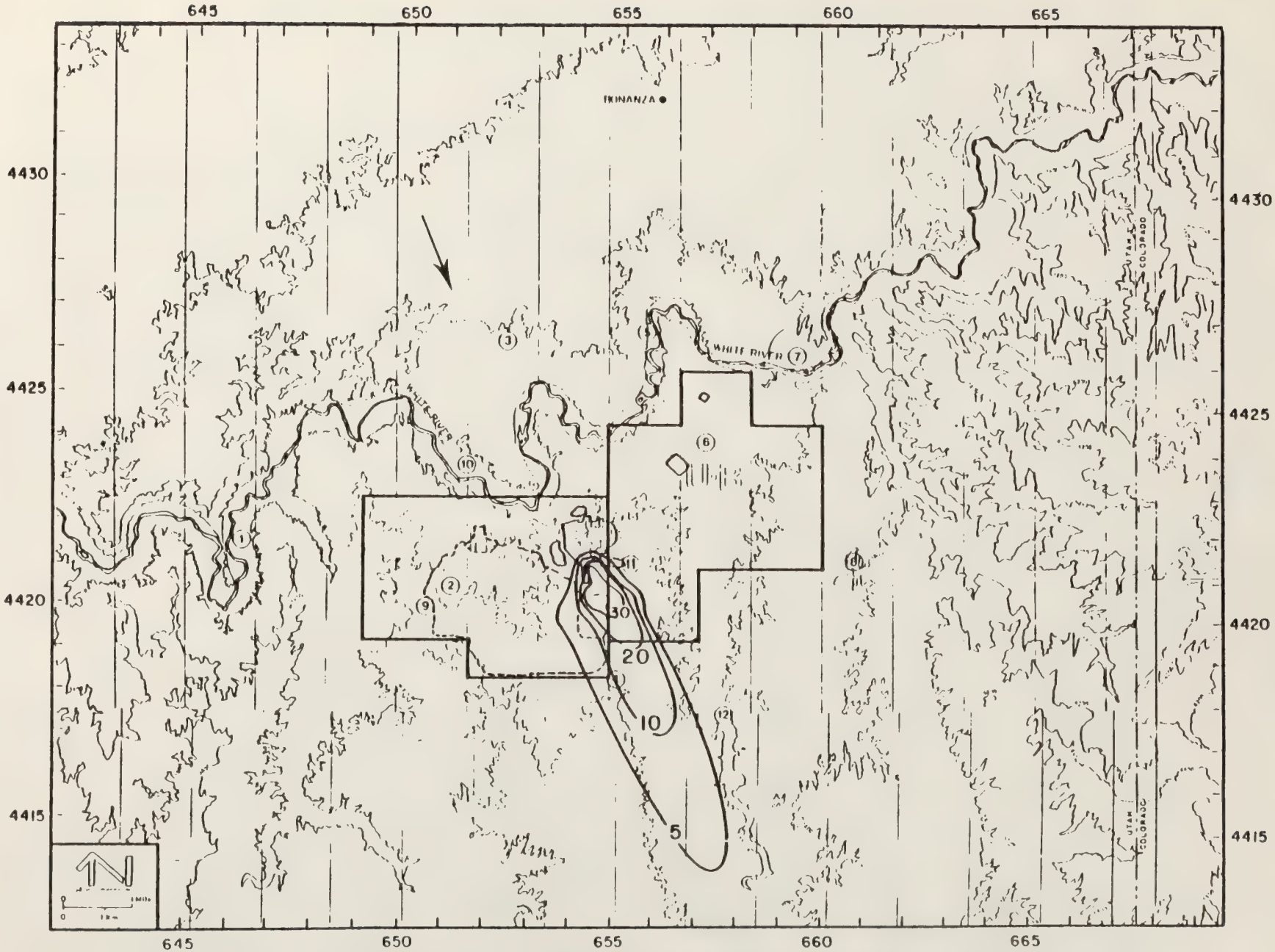


Figure 7-14 CONCENTRATION ISOPLETHS OF WORST-CASE PHASE III SO_2 24-HOUR AVERAGE INCREMENTS ($\mu g/m^3$). ARROW DENOTES WIND DIRECTION.

a large area (especially for particulates). Therefore, the maximum concentrations are not always directly downwind of the grid center but represent the area with the highest combination of source impacts.

Phase I. For particulate, the worst-case wind direction was found to be from the north. This direction combined source emissions in the process area with processed shale disposal emissions to give maximum off-tract impacts near the southeast corner of Tract Ua. The highest 24-hour average particulate increment predicted at this location was 7.7 $\mu g/m^3$. This concentration is well below the Class II PSD allowable increment of 37 $\mu g/m^3$. Including background, the prediction becomes 23.4 $\mu g/m^3$, which is less than 16 percent of the NAAQS secondary standard of 150 $\mu g/m^3$.

From the joint frequency distribution of wind and stability (Table 7-3) during the five year data base, the frequency-of-occurrence of this meteorology (2.5 meter-per-second wind from the north with F stability) is less than 0.02 percent of the time. The highest frequency-of-occurrance of F stability with any wind direction and 2.5-meter-per-second wind speed at Site A6 is 1.5 percent of the observations, occurring with south-southeast winds at 30 meters above ground. The total frequency-of-occurrence of F stability/2.5-meter-per-second wind for all directions in any given hour is less than 3 percent. Since each observation corresponds to a single hour, the frequency of occurrence of 6 hours of these meteorological conditions during any given 24 hours would be much lower.

Maximum short-term SO_2 Phase I averages will occur with a south-southeasterly wind direction. The maximum off-tract 24-hour average SO_2 increment of 22.7 $\mu g/m^3$ is predicted to occur just north of the process area near the steam plant boiler and is also below the Class II PSD allowable increment of 91 $\mu g/m^3$ for this averaging time. This value with background is 24.0 $\mu g/m^3$, which is less than 10 percent of the 365 $\mu g/m^3$ NAAQS value. The 3-hour averages can be scaled from the 24-hour averages predicted by

modified-VALLEY by a factor of 2.5 (Ref. 7-11). The maximum 3-hour average SO_2 increment is then predicted to be 57.8 $\mu g/m^3$ or 59.1 $\mu g/m^3$ with background, less than 12 percent of PSD 3-hour value of 512 $\mu g/m^3$, and less than 5 percent of the 1,300 $\mu g/m^3$ NAAQS 3-hour value. This meteorology 2.5-meters-per-second south-southeast wind/F stability) occurred during about 1.5 percent of the hours at Site A6 in the five-year data base.

Maximum 24-hour incremental averages during Phase I in the vicinity of the construction camps for SO_2 and particulates are 4.5 and 2.7 $\mu g/m^3$ respectively. These concentrations are predicted assuming a southwesterly wind.

Maximum short-term CO concentrations for Phase I were obtained by running modified-VALLEY and adjusting the outputs to represent 1- and 8-hour averages. These outputs show maximum CO concentrations off-tract to be less than 0.1 mg/m^3 for both averaging times. Even with the background value of 0.1 mg/m^3, these concentrations are well below the one- (40 mg/m^3) and eight-hour (10 mg/m^3) NAAQS.

Phase II. The worst-case 24-hour average TSP increment for Phase II was predicted to occur under the same wind direction (north) and location as the maximum predicted for Phase I TSP in the short-term. The value here of 21.2 $\mu g/m^3$ is below the 37 $\mu g/m^3$ PSD Class II standard. With background, the maximum of 36.9 $\mu g/m^3$ is below 25 percent of NAAQS secondary standard of 150 $\mu g/m^3$.

The maximum off-tract Phase II 24-hour average SO_2 increment was predicted to occur with a north-northwest wind at the southern junction of Tracts Ua and Ub. This maximum occurred here due to the higher terrain elevations south of the tracts.

The incremental value at this location was 17.6 $\mu g/m^3$ or 18.9 $\mu g/m^3$ with background, again slightly lower than the Phase I values due to the addition of control technology. These values are below both the PSD standard of 91 $\mu g/m^3$ and the NAAQS of 365 $\mu g/m^3$.

The maximum 3-hour average SO_2 impact predicted using the 2.5 factor is 47.3 $\mu g/m^3$. With background, the maximum 3-hour average is 48.6 $\mu g/m^3$. Neither the PSD increment (512 $\mu g/m^3$) nor the NAAQS (1300 $\mu g/m^3$) would be exceeded. The worst-case meteorology for this scenario (2.5 meter-per-second wind from north-northwest with F stability) is predicted to occur 0.2 percent of the time during the five-year data base.

Again, a scenario including construction emissions similar to that discussed for annual averages was modeled in the short-term. Peak construction emission estimates of 9,348 lb/day of fugitive dust were assumed. For this case, the maximum off-tract particulate concentration, including background, of 131.8 $\mu g/m^3$ occurred with a south-southeast wind near the northern boundary of the tracts. This value is less than the 150 $\mu g/m^3$ secondary NAAQS so no exceedances should be expected for the life of the project.

Phase III. The worst-case 24-hour average particulate increment for Phase III is predicted to occur under the same wind direction (north) and location (south of the processed shale disposal pile) as the maximum predicted for Phases I and II particulate in the short-term. The value here of 36.8 $\mu g/m^3$ is approximately equal to the PSD Class II standard of 37 $\mu g/m^3$. With background, the maximum of 52.5 $\mu g/m^3$ is below 35 percent of NAAQS secondary of 150 $\mu g/m^3$.

The maximum off-tract Phase III 24-hour average SO_2 increment is predicted to occur with a north-northwest wind near the same location as the Phase II maxima. The incremental value at this location is 20.6 $\mu g/m^3$ of 21.9 $\mu g/m^3$ with background. These values are below both the PSD standard of 91 $\mu g/m^3$ and the NAAQS of 365 $\mu g/m^3$.

The maximum 3-hour average SO_2 impact predicted using the 2.5 factor is 51.5 $\mu g/m^3$. With background, the maximum 3-hour is 52.8 $\mu g/m^3$. Neither the PSD increment (512 $\mu g/m^3$) nor the NAAQS (1300 $\mu g/m^3$) would be exceeded.

The worst-case meteorology for these scenarios (2.5-meter-per-second wind from north-northwest with F stability) is predicted to occur 0.02 percent of the time during the five-year data base.

During Phase III, maximum 24-hour above-background averages at the construction and RV camps are predicted to be 5.3 $\mu g/m^3$ for SO_2 and 10.3 $\mu g/m^3$ for particulates. These concentrations are well-below standards.

Maximum short-term off-tract CO impacts for Phase III are again predicted to be less than 0.3 mg/m^3 or 0.5 mg/m^3 with background for all wind directions.

7.4.2 Secondary Pollutant Predictions

The only secondary pollutant having a national ambient air quality standard is ozone. The standard is for the peak one-hour average ozone concentration and these REM2 predicted impacts will be discussed. There are no PSD increments for ozone.

Peak Ambient Local Precursor-Related Ozone Scenario

An air parcel in the Uinta Basin near Tracts Ua and Ub on a day of high ozone concentrations (without the project) was simulated to match model predictions with actual ozone formation in the area. This scenario is summarized in Table 7-15. The time of day is indicated along with the total distance of travel (assuming uniform 1.0-meter-per-second wind transport) of the parcel from its initial arbitrary location at 0600 MST. The concentration of O_3, NO_2, NO, and total NMHC in the moving column also represent the temporal concentration profiles at any ground-fixed position in the area as well as along the trajectory because of the assumptions that the 0600 MST background is uniformly distributed spatially and no sources or sinks of pollutants are present. The maximum predicted O_3 concentration of 126 $\mu g/m^3$ at 1700 MST matches closely (within 13 percent) the O_3 peak value monitored on Tracts Ua and Ub.

Table 7-15

REM2 AMBIENT PHOTOCHEMICAL OXIDANT SCENARIO

Hour (MST)	Travel Distance (km)	One-Hour Average Concentrations			NMHC ($\mu g/m^3$)
		O_3	NO_2	NO	
0600	0.0	90	5	5	66
0700	3.6	88	11	1	66
0800	7.2	92	11	1	59
0900	10.8	96	10	1	59
1000	14.4	100	10	1	52
1100	18.0	105	10	1	46
1200	21.6	111	10	1	39
1300	25.2	114	10	1	33
1400	28.8	120	10	1	26
1500	32.4	123	10	1	20
1600	36.0	126	9	1	20
1700	39.6	126	9	1	20

Phase I Ozone Scenario

A trajectory over the WRSP grid during Phase I with the same background concentrations used for the ambient scenario is summarized in Table 7-16. The parcel passes over the process area between 0630 and 0700 MST as shown by the drop in O_3 and NO concentrations and the large increase in NO_2 near these times. Figure 7-15 shows the O_3 concentration versus time for this trajectory along with the ambient O_3 trajectory predictions. Travel distance from the center of the emission grid is also indicated.

The maximum predicted one-hour ozone concentration downwind of the Phase I scenario of 113 $\mu g/m^3$ is 90 percent of the peak value predicted without Phase I emissions. This predicted decrease is probably due to the scavenging of ozone by the increased NO emissions. This peak value also occurs earlier in the day (1600 MST) than the ambient scenario (1700 MST). The 113 $\mu g/m^3$ maximum is 48 percent of the maximum hour national standard of 235 $\mu g/m^3$ so no exceedances are predicted.

Phase III O_3 Scenario

Table 7-17 summarizes the trajectory simulation for the air parcel passing over the WRSP Phase III source near 0700 MST. The O_3 concentration is plotted in Figure 7-15. The maximum downwind O_3 concentration of 135 $\mu g/m^3$ occurs near 1600 MST but is slightly larger than the maximum one-hour ambient ozone concentration of 126 $\mu g/m^3$. This is due principally to the large increase in NO_x emissions, with the mine mobile equipment and power plants being the dominant sources.

The maximum predicted one-hour average O_3 concentration downwind of the Phase III source area is 135 $\mu g/m^3$. This value is approximately 57 percent of the national standard of 235 $\mu g/m^3$, so no exceedances are foreseen.

7.4.3 Non-Criteria Pollutant Impacts

Besides the pollutants covered by NAAQS, PSD rules require an air quality analysis of all pollutants regulated under the Clean Air Act. This

Table 7-16

REM2 PHASE I PHOTOCHEMICAL OXIDANT SCENARIO

Hour (MST)	Travel Distance (km)	One-Hour Average Concentrations			NMHC ($\mu g/m^3$)
		O_3	NO_2	NO	
0600	0.0	90	5	5	66
0700	3.6	82	15	1	66
0800	7.2	86	16	2	59
0900	10.8	92	14	2	59
1000	14.4	97	13	2	52
1100	18.0	102	13	2	46
1200	21.6	106	12	2	39
1300	25.2	108	11	1	33
1400	28.8	111	11	1	26
1500	32.4	113	11	1	20
1600	36.0	113	10	1	20
1700	39.6	112	10	1	20

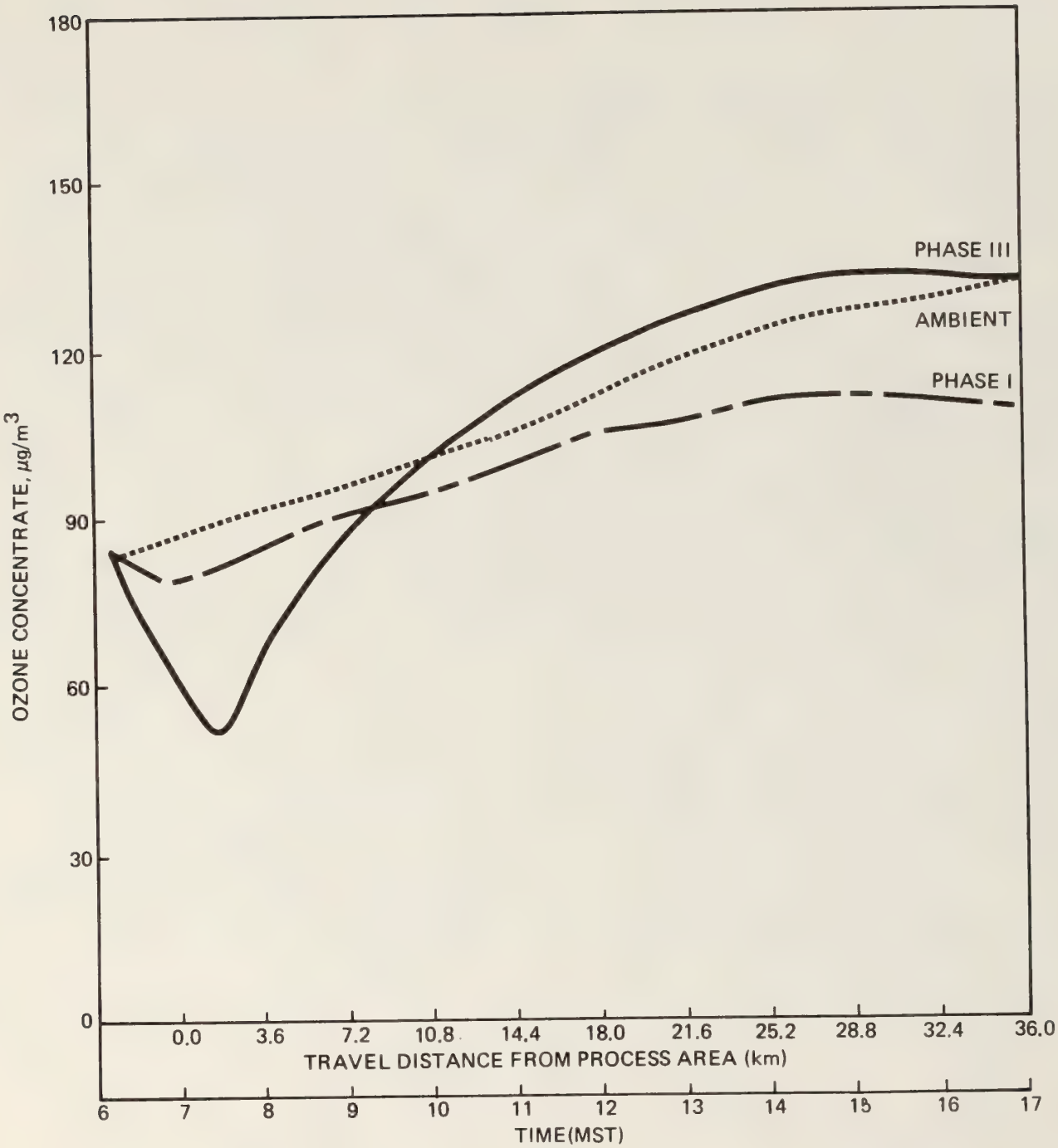


Figure 7-15 REM2 OZONE SCENARIOS

Table 7-17

REM2 PHASE III PHOTOCHEMICAL OXIDANT SCENARIO

Hour (MST)	Travel Distance (km)	One-Hour Average Concentrations			NMHC ($\mu g/m^3$)
		O_3	NO_2	NO	
0600	0.0	90	5	5	66
0700	3.6	62	36	5	72
0800	7.2	66	44	7	66
0900	10.8	86	36	5	59
1000	14.4	100	31	4	52
1100	18.0	111	29	3	46
1200	21.6	120	27	3	33
1300	25.2	126	24	3	26
1400	28.8	132	23	2	20
1500	32.4	134	21	2	20
1600	36.0	135	20	1	13
1700	39.6	133	19	1	13

requirement includes pollutants regulated by the New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAP). The only such pollutant found to be emitted in significant amounts for the WRSP was sulfuric acid (H_2SO_4) mist. As discussed in Section 5, 8, 13, and 18, 56-tons-per-year of this pollutant will be emitted during Phase I, II, and III operation, respectively after BACT is applied, thus exceeding the seven-ton-per-year de minimis level.

PSD regulations state that, "with respect to any such pollutant for which no National Ambient Air Quality Standards exist, the analysis shall contain such air quality monitoring data as the reviewing authority determines is necessary to assess ambient air quality for that pollutant in any area that the emissions of that pollutant would affect." However, the regulations also state that "No satisfactory monitoring technique is available at this time" for sulfuric acid mist. Therefore, a modeling analysis was substituted for the monitoring.

Modeling of H_2SO_4 mist was done similarly to that of the other pollutants using the modified VALLEY model. Although it is possible that an acid mist would behave differently than a gaseous pollutant, no EPA guideline models are currently available which take these differences into consideration.

Health effects in animals and humans exposed to H_2SO_4 mist have been found for exposures ranging from 5 minutes to 140 days, under various concentrations. A 24-hour scenario was assumed to be an approximate median of these averaging times so was chosen for modeling. These simulations predicted the highest off-tract 24-hour average concentrations of H_2SO_4 during Phase III would be 0.5 $\mu g/m^3$, and that the highest 24-hour average concentration at the construction camp would be 0.2 $\mu g/m^3$. Although no air quality value is given in the PSD regulations to determine the significance of the values, they are much lower than concentrations found to cause effects in health studies (Reference 7-12). Concentrations between 10 and 100 $\mu g/m^3$ have not been shown to have any effect on healthy human individuals, except for

possible synergistic effects in the presence of hydrogen peroxide and sulfur dioxide. The much lower level expected due to the WRSP then should not cause health impacts in the area. Concentrations during Phases I and II should be lower corresponding to the lower emissions.

7.4.4 Project Impacts on Pristine Areas

The nearest Mandatory Class I areas to the WRSP operation are the Flat Tops Wilderness area 130 kilometers to the east, and Arches National Park 130 kilometers to the south. Dinosaur National Monument, however, is approximately 55 kilometers to the north of the proposed project, and has been under consideration for redesignation to a Class I area. (These areas were shown in Figure 7-1.) Impacts for the PSD criteria pollutants were calculated using modified VALLEY at Dinosaur National Monument in order to predict the upper limit of the increments attributable to project air pollutant emissions at pristine areas. It is expected that impacts at the other areas will be less than values projected for Dinosaur because of the greater distance.

A special receptor grid centered in Dinosaur was used to determine impacts in this area. Receptors were spaced about every 3 kilometers so that the entire park could be studied, including a range of elevations at the various distances. Elevations in the park range from about, 5,000 to 8,000 feet MSL.

Annual average increments for Phase I were predicted to be 0.056 and 0.029 $\mu g/m^3$ for SO_2 and particulates, respectively. The corresponding values for Phase III are 0.12 and 0.15 $\mu g/m^3$. These impacts are well under the annual average Class I PSD increments of 2 $\mu g/m^3$ and 5 $\mu g/m^3$.

The highest expected 24-hour average increments were predicted with a 2.5-meter-per-second wind blowing directly from the WRSP to Dinosaur during stability Class F. The maximum values predicted were 0.13 and 0.09 $\mu g/m^3$ for Phase I SO_2 and particulates, respectively, and 0.30 and 0.43 $\mu g/m^3$

for Phase III SO_2 and particulates, respectively. These maximum impacts are all lower than the Class I 24-hour average PSD incremental standards of 5 and 10 g/m^3.

7.4.5 Cumulative Impacts

As part of the PSD requirements, an analysis must demonstrate that, in conjunction with other sources in the area permitted to operate after the baseline air quality has been established, this project will not cause PSD increments to be accumulated over the allowed levels. Therefore, it was necessary to determine what sources have been permitted that could consume increments near the WRSP area of impact.

The only sources in the Uinta Basin which had applied for and received PSD permits by July 1, 1981 were a small oil shale demonstration project operated by Geokinetics Inc. and the Moon Lake Project coal-fired electric generating utility operated by Deseret Generation and Transmission Cooperative. Tosco Corp. has also submitted an application for an oil shale operation at their Sand Wash property. This application is currently being reviewed. The Geokinetics source is located in Section 2 of T14S, R22E, about 35 kilometers southwest of Tract Ua. The Moon Lake utility is to be located on a property in parts of Section 23-25, 35-36 of T8S, R23E and Sections 1-2 of T9S, R23E, which is about 18 kilometers north-northwest of Tract Ua. Tosco's properties consist of sections in T9S, R20E; T9S, R21E; T9S, R22E; T10S, R21E; and T10S, R22E, with the proposed plant site located about 25 kilometers west-northwest of Tract Ua.

The Geokinetics project is permitted to operate only from 1980 to 1983. WRSP Phase I construction is the only work planned during this time. Since the WRSP emissions would consist mainly of fugitive particulates, there should be no significant interaction between the two projects. Therefore, no cumulative analysis was performed for WRSP and Geokinetics.

The Deseret Generation and Transmission Cooperative is proposing to build two 400 megawatt coal-fired electricity generating units for the Moon Lake project. The first unit is expected to begin operating in December 1984, with Unit 2 not expected to be operating until 1999. The PSD permit issued for this source specifies emission limitations for Unit 1 and Unit 2, but required further review when Unit 2 construction commences. The emission rates and source characteristics used for this source are given in Table 7-18.

Tosco proposed to begin construction of their Sand Wash project in 1983, with the plant reaching 75 percent operation in 1988 and full operation in 1989. The emission rates and source characteristics for this proposed operation are given in Table 7-19.

In order to determine the maximum cumulative impacts, a scenario was analyzed which would include operation of WRSP Phase III, both Moon Lake units and the full-capacity Tosco project. This combination would not occur until 1999 and it can be assumed that impacts before that time would be less since the emissions would be lower. Annual impacts for this scenario were analyzed with the meteorological frequency distribution given in Table 7-3. Besides the receptor grid networks in the vicinity of Tracts Ua and Ub and at Dinosaur National Monument, described in earlier sections, a number of additional receptors in the vicinities of the Moon Lake and Sand Wash projects were modeled. These receptors were chosen to represent areas where maximum impacts could be expected (i.e., near the projects and at high elevations potentially subject to plume impact).

The maximum annual average SO_2 concentration increment during this scenario is predicted to be 14.1 $\mu g/m^3$. This concentration is predicted for the same near-tract receptor where Phase III WRSP impacts alone are predicted to about 13.7 $\mu g/m^3$. This value is well below the SO_2 annual average Class II PSD standard of 20 $\mu g/m^3$. The cumulative annual average SO_2 increment maximum at Dinosaur is 0.39 $\mu g/m^3$. This value is well-below the 2 $\mu g/m^3$ SO_2 Class I annual average increment.

TABLE 7-18

SOURCE CHARACTERISTICS FOR MOON LAKE GENERATING STATION

Source	Approximate Location UTM, Zone 12		Emissions in lb/hr (g/s)			Stack Data			
	E (km)	N (km)	SO_2	TSP	NO_x	SH (m)	D (m)	T (K)	VF (m^3/s)
Unit 1	646.31	4,438.46	405.5 (51.1)	121.7 (15.3)	2230.2 (281.0)	171.45	7.92	321.77	660.73
Units 1 and 2	646.31	4,438.46	417.5 (52.6)	243.3 (30.6)	4460.5 (562.0)	171.45	7.92	321.77	660.73

Table 7-19 SOURCE CHARACTERISTICS FOR TOSCO'S SAND WASH PROJECT

Source	Emissions in lb/hr (g/s)					Stack Data			
	SO_2	NO_x	HC	TSP	CO	SH (m)	D (m)	T (K)	VF (m^3/sec)
Area A:									
Preheat Stacks	37.4 (7.232)	1477.9 (186.215)	300.0 (37.799)	90.0 (11.340)	49.0 (6.174)	95.00	2.80	326.00	97.29
Processed Shale Wetters	-- --	-- --	-- --	42.6 (5.368)	-- --	95.00	1.40	330.00	21.86
Cold Ball Elutriators	105.0 (13.230)	126.0 (15.876)	0.3 (0.038)	42.0 (5.292)	3.2 (0.403)	95.00	1.40	330.00	21.86
Sulfur Plants	105.0 (13.230)	-- --	-- --	-- --	-- --	64.00	2.40	422.00	49.76
Hydrogen Furnaces	30.1 (3.793)	90.3 11.378	1.8 (0.227)	12.7 (1.600)	10.8 (1.361)	24.00	1.70	500.00	34.50
Naptha Heaters	0.5 (0.063)	1.4 (0.176)	0.1 (0.013)	0.2 (0.025)	0.2 (0.025)	23.00	0.80	700.00	3.67
Gas Oil Heaters	1.0 (0.126)	3.0 (0.378)	0.013 (0.123)	0.4 (0.050)	0.4 (0.050)	23.00	0.80	755.00	5.38
Gas Oil Reboiler	4.0 (0.504)	12.1 (1.525)	0.2 (0.025)	1.8 (0.227)	1.4 (0.176)	46.00	1.70	644.00	24.97
Coker Feed Heater	3.1 (0.391)	9.3 (1.172)	0.2 (0.025)	1.2 (0.151)	1.1 (0.139)	53.00	2.30	450.00	56.92
Boilers	8.0 (1.008)	24.0 (3.024)	0.5 (0.063)	3.2 (0.403)	2.9 (0.365)	17.00	2.10	477.00	26.32
Secondary Crushers	-- --	-- --	-- --	36.6 (4.612)	-- --	22.00	1.50	294.00	27.39
Fine Ore Storage	-- --	-- --	-- --	4.7 (0.592)	-- --	5.00	1.20	294.00	16.51
Utility Boilers	0.5 (0.063)	0.8 (0.101)	-- --	0.1 (0.013)	0.1 (0.013)	5.00	0.40	505.00	0.65
Transfer Points	-- --	-- --	-- --	0.8 (0.101)	-- --	15.00	--	A	--
Reclaim Tunnel	-- --	-- --	-- --	6.2 (0.781)	-- --	10.00	--	A	--
Spent Shale Storage	-- --	-- --	-- --	7.9 (0.995)	-- --	15.00	--	A	--
Delayed Coker Dumper	-- --	-- --	-- --	0.1 (0.013)	-- --	15.00	--	A	--

Table 7-19 SOURCE CHARACTERISTICS FOR TOSCO'S SAND WASH PROJECT (continued)

Coarse Ore Storage	-- --	-- --	-- --	1.1 (0.139)	-- --	15.00	--	A	--
Production Shaft	-- --	-- --	-- --	0.2 (0.025)	-- --	10.00	--	A	--
Conveyors between Areas "A" & "C"	-- --	-- --	-- --	0.7 (0.088)	-- --	10.00	--	A	--
Misc. Unpaved Roads	-- --	-- --	-- --	2.6 (0.328)	-- --	5.00	--	A	--
Mine Vents	-- --	-- --	-- --	6.6 (0.832)	-- --	3.10	--	A	--
HC Storage	-- --	-- --	32.5 (4.095)	-- --	-- --	--	--	A	--
Misc. HC Fugitive Emissions	-- --	-- --	64.9 (8.17)	-- --	-- --	--	--	A	--
Area B:									
Transfer Points	-- --	-- --	-- --	0.2 (0.025)	-- --	15.00	--	A	--
Production Shaft	-- --	-- --	-- --	0.1 (0.013)	-- --	10.00	--	A	--
Conveyors between Areas "B" & "C"	-- --	-- --	-- --	0.7 (0.088)	-- --	10.00	--	A	--
Misc. Unpaved Roads	-- --	-- --	-- --	1.8 (0.227)	-- --	5.00	--	A	--
Mine Vents	-- --	-- --	-- --	4.4 (0.554)	-- --	3.10	6.00	311.00	313.85
Area C:									
Transfer Points	-- --	-- --	-- --	0.2 (0.025)	-- --	15.00	--	A	--
Production Shaft	-- --	-- --	-- --	0.1 (0.013)	-- --	10.00	--	A	--
Misc. Unpaved Roads	-- --	-- --	-- --	0.9 (0.113)	-- --	5.00	--	A	--
Mine Vents	-- --	-- --	-- --	2.2 (0.277)	-- --	3.10	6.00	311.00	158.34

UTM Coordinates: Area A = 625.13, 4428.13; Area B = 629.50, 4422.75; Area C = 636.75, 4425.50

Maximum annual average cumulative TSP values are predicted to be well below both Class II and I standards. A cumulative impact of 16.5 $\mu g/^3$ was predicted near the WRSP tracts (compared to the 19 $\mu g/m^3$ PSD Class II standard) and 0.32 $\mu g/m^3$ at Dinosaur (compared to the 5 $\mu g/m^3$ Class I standard). All other values in these areas were less.

Maximum annual average cumulative NO_2 concentration from the three projects is predicted to be 79.2 $\mu g/m^3$; with background, this value would be 80.5 $\mu g/m^3$, which is well below the NAAQS 100 $\mu g/m^3$ level.

To determine maximum 24-hour cumulative impacts, wind directions were chosen which would align the other proposed projects with the WRSP. These included WNW and ESE aligning Tosco and White River and NNW and SSE aligning Moon Lake and White River. The wind speed was again assumed to be about 2.5 m/sec and with class F (stable) stability.

When Moon Lake and White River are aligned, the maximum SO_2 24-hour concentration occured with the NNW wind near the south-east corner of Tract Ua. This value of 22.0 $\mu g/m^3$ is below the SO_2 PSD Class II standard 91 $\mu g/m^3$. The off-tract maximum with Sand Wash and White River aligned was less at 13.2 $\mu g/m^3$.

For particulate, the Moon Lake-White River alignment was again higher than Tosco-White River with 24-hour values of 29 $\mu g/m^3$ and 12.3 $\mu g/m^3$ respectively. However, both values are less than the 36.8 $\mu g/m^3$ value observed from White River alone using a northerly wind. All values are below the 37 $\mu g/m^3$ PSD standard.

At Dinosaur National Monument, maximum 24-hour impacts were predicted using wind directions which would transport emissions from all three projects toward Dinosaur. (i.e., SSW, SW, and S). In this case, the maximum SO_2 24-hour cumulative impact of 0.81 $\mu g/m^3$ which is below the SO_2 Class I

standard of 5 $\mu g/m^3$. The TSP 24-hour cumulative impacts in Dinosaur was 0.60 $\mu g/m^3$, well below the 24-hour Class I standard of 10 $\mu g/m^3$ for TSP.

The analysis shows that the WRSP can operate in this area in conjunction with the other mentioned projects without exceeding applicable standards. At the most, only 20 percent of the Class I SO_2 increment and 7 percent of the Class I TSP increment will be consumed. Although the Class II increments are approached for an annual and 24-hour average TSP, these concentrations are predicted to occur very close to the WRSP tract boundaries and are expected to drop off quickly farther from the property. This drop-off should still leave PSD increment available to other projects wishing to locate in this area.

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Section 8

ADDITIONAL IMPACT ANALYSES

In accordance with federal regulations (40 CFR 42.21 (o), (p)), air quality impact analyses have been performed in addition to those discussed in Section 7. Specifically, these include:

- Air quality impact from associated population growth
- Impact on visibility
- Impact on vegetation and soils

8.1 ASSOCIATED GROWTH

As discussed previously, the proposed facility will be constructed in three phases. The work force for both construction and operation of the facility will come from a combination of local and nonlocal sources. The estimated increase in direct and indirect employment created by the proposed project is shown in Table 8-1. This table also shows the total anticipated increase in regional population. Figure 8-1 shows graphically the expected fluctuation of direct and indirect employment and regional population.

Direct employment figures were based upon estimates of the construction and operations work force for WRSP. Indirect employment figures were estimated by developing a multiplier to project the nonbasic or service employment from direct employment. This multiplier was developed from detailed employment data for all counties in the region and applying proven statistical methods to the data. Specifically, nonbasic employment was regressed on basic employment, taking into consideration the distance of the proposed project from major metropolitan centers and the size of the existing regional economy.

Table 8-1

ESTIMATED POPULATION GROWTH

Phase	Year of Peak Employment	No. of Employees		Population Growth		
		WRSP Direct Incoming	WRSP Indirect Incoming	WRSP Direct Incoming	WRSP Indirect Incoming	Total WRSP-Induced
I	1983	1,472	443	3,314	1,329	4,643
II	1989	3,938	3,763	9,247	11,290	20,537
III Construction	1991	3,566	4,199	8,690	12,597	21,287
III Operation	1994	2,012	4,023	5,395	12,069	17,464

Total population increases shown in Table 8-1 were also estimated using multipliers derived from historical data and applying it to the total number of new jobs created as a direct result of WRSP development. The maximum population increase attributable to the project is expected to be 21,287 persons during Phase III construction (1991). During Phase III operation, total population growth associated with the project is expected to decline to about 17,464 persons.

To estimate the increase in emissions due to this growth in regional population, pollutant factors were derived from numbers available from the Utah State Implementation Plan (Ref. 8-1), comparing 1970 Uintah County population with 1970 Uintah County area source emissions. Only area sources were used because these sources, such as fuel combustion and transportation, are most directly associated with population growth. Table 8-2 gives these factors and the emission increases derived from them. Comparisons of these factors with other sparsely populated counties show them to be generally applicable.

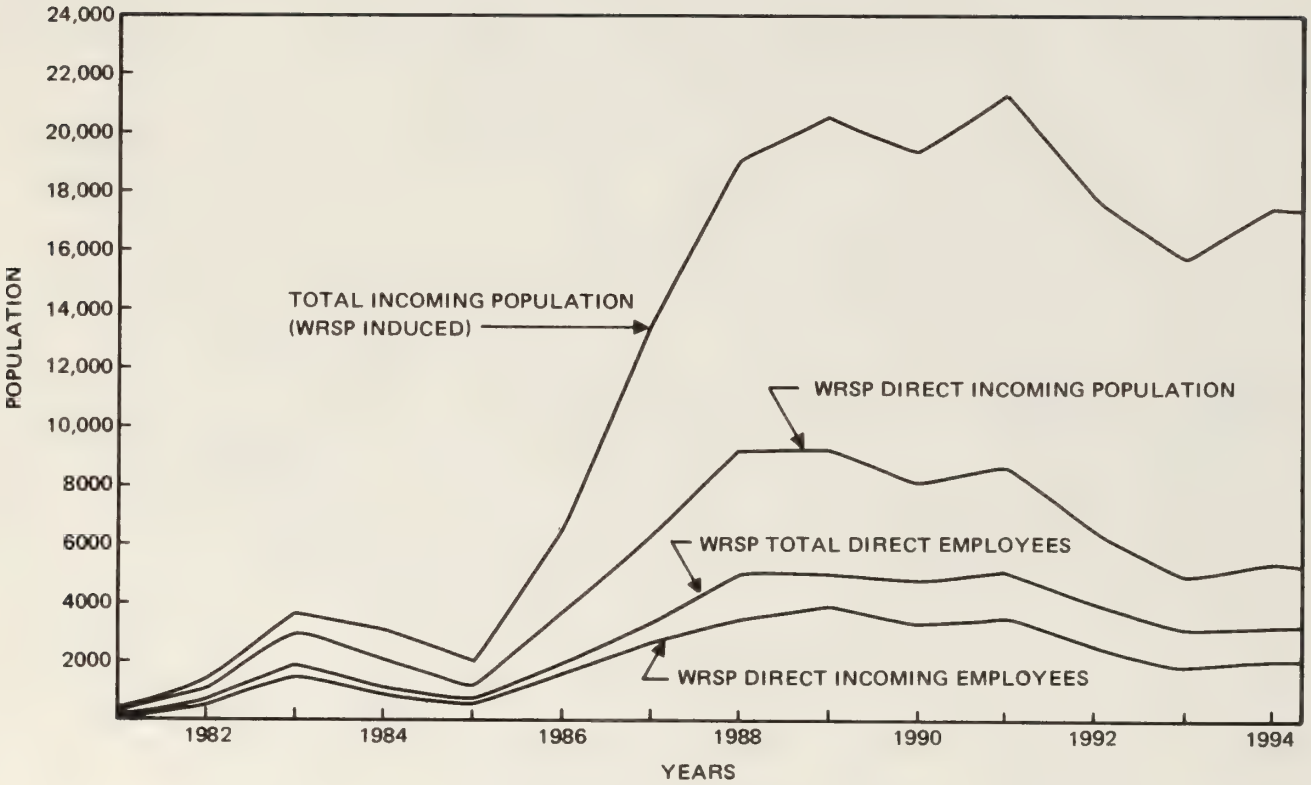

Figure 8-1 EMPLOYMENT AND POPULATION CURVES

The air quality impacts of this increase in area source emissions can be assessed by comparing the increase with direct WRSP facility emissions (Table 7-1) for which air quality forecasts were made in Section 7. A summary of relative emission increases is provided in Table 8-3 for Phases I and III.

Increases in population-growth-induced emissions of SO_2, TSP, and NO_x during Phase III are 14.7, 13.9, and 28.2 percent of the corresponding WRSP Phase III project emissions. These emissions are not expected to exceed any air quality standards, especially since they will be distributed throughout the region rather than concentrated in one area as the project emissions will be.

Although population-growth-induced CO emissions are higher than direct project emissions, low concentrations would still be expected due to the very low CO levels predicted for WRSP project CO emissions. Population growth hydrocarbon emissions are also higher than the direct project emissions. However, if the background levels of NO_x and hydrocarbon used in the ozone predictions given in Section 7.4 are increased proportionally to the increase in growth-induced regional emissions, the ozone is predicted to increase by about 55 $\mu g/m^3$ (from 135 $\mu g/m^3$ to 190 $\mu g/m^3$). This is still well below the current 235 $\mu g/m^3$ standard. However, this predicted concentration is probably a very conservative estimate, since such a direct relationship between background air quality at the tracts and regional area source emissions is unlikely.

8.2 VISIBILITY

8.2.1 Analysis Requirements

Section 165(e) of the Clean Air Act prescribes, as a portion of the preconstruction requirements of a PSD permit, that an analysis be performed of the "ambient air quality...and visibility at the site of the proposed major emitting facility and in the area potentially affected by the emissions from such a facility." According to Section 165(d)(2)(c)(ii), if the Federal

Table 8-2

POLLUTANT FACTORS FOR UINTAH COUNTY
RELATING EMISSIONS TO POPULATION

Pollutant/ Population	1970 Area Source Emissions (TPY)	Pollutant Factor (TPY/Person)	Emissions Associated With Population Growth (TPY)			
			Phase I	Phase II	Phase III Construction	Phase III Operation
Pollutant						
TSP	150	0.012	56	246	255	210
SO_2	125	0.010	46	205	213	175
NO_x	1,487	0.119	523	2,444	2,533	2,078
CO	9,599	0.769	3,570	15,793	16,370	13,430
HC	1,727	0.138	641	2,834	2,938	2,410
Population	12,479	NA	4,643	20,537	21,287	17,464

Table 8-3

COMPARISON OF WRSP PROJECT AND TOTAL POPULATION
GROWTH EMISSIONS FOR PHASES I AND III
(TPY)

Pollutant	Phase I Emissions		Phase III Emissions	
	Project	Population	Project	Population
TSP	285	56	1,515	210
SO_2	510	46	1,175	175
NO_x	1,236	523	7,366	2,078
CO	477	3,570	3,407	13,430
HC	190	641	1,477	2,410

Land Manager responsible for any Class I PSD area "demonstrates to the satisfaction of the state that the emissions from such facility will have an adverse impact on the air quality related values (including visibility) of such lands...a permit shall not be issued." Thus, above and beyond demonstrating that the proposed facility will not exceed the appropriate PSD increments for SO_2 and suspended particulate matter, it is necessary to demonstrate that the facility will not have adverse visibility impacts on any Class I area.

8.2.2 Methodology

As recommended in the EPA Workbook for Estimating Visibility Impairment (Ref. 8-2), a Level-1 screening analysis was performed to assess potential visibility impacts on the nearest proposed Class I area, Dinosaur National Monument. This first test can be done quickly, and it immediately identifies those emission sources that are unlikely to adversely affect the visibility in a Class I area. The input parameters needed for a Level-1 screening analysis are:

- Minimum distance of the emissions source from a potentially affected Class I area
- Locations of emissions source and Class I area
- Particulate emission rate
- NO_x emission rate
- SO_2 emission rate
- Vertical dispersion coefficient
- Background visual range

The screening technique considers two different types of visibility impairment — one caused principally by NO_2 gas from NO_x emissions, and the other caused by particulate emissions and sulfate aerosol formed from SO_2 emissions. The NO_2-impaired vista is seen as a discolored,

dark plume against a bright horizon sky or as a bright plume against a dark terrain background. The viewing path impaired by high aerosol concentration is characterized by regional haze.

Worst-case meteorological conditions (Pasquill-Gifford Class F stability) are assumed in the analysis in order to predict the greatest potential visibility impairment.

Other inputs to the procedure are the vertical dispersion coefficient for the given downwind distance of the Class I area from the source and the regional background visual range value for the geographic region in question.

8.2.3 Results

This analysis indicates that the worst conceivable visibility impact from the WRSP at the Dinosaur National Monument is likely to be minimal in terms of both plumes visible against the sky and plumes visible against the terrain, and is expected to be insignificant or imperceptible in its effect on the visual range and sky-terrain contrast. This should also be true at the closest Mandatory Class I area, Flat Tops Wilderness Area, especially due to the greater distance and effects of intervening topography on dispersion.

To obtain the absolute contrast values for comparison with the visibility workbook's recommended limits, calculations were done, as described below.

Plume Dispersion Parameter. The vertical dispersion coefficient, σ_z, was read from the curves in Turner's Workbook (Ref. 8-3) for a downwind distance (X) of 55 km (from Tracts Ua and Ub to the nearest Dinosaur National Monument area border at Yampa Plateau) for Stability Class F.

The plume dispersion parameter, p, was then calculated using the equation from Reference 8-2:

$$p = \frac{2 \times 10^8}{\sigma_z(m)\ X(km)}$$

$$p = \frac{2 \times 10^8}{(85)(55)}$$

$$p = 4.28 \times 10^4$$

Optical Thickness for Particulate and NO_2. Optical thicknesses were calculated for both particulate (τ_{part}) and NO_2 (τ_{NO_2}) from the total mass emission rates (Q), for all emissions released through stacks, baghouse exhausts, and mine exhausts. Other releases from storage piles and transfer points at Tracts Ua and Ub do not contribute to a coherent plume that would travel 55 km intact and be able to clear the cliffs north of the White River. Therefore, the inputs to the calculations were:

		Phase I	Phase II	Phase III
Q_{NO_x}	=	3.42	11.32	20.35 metric tons/day
Q_{part}	=	0.39	1.51	2.94 metric tons/day

Then, optical thickness is calculated by:

$$\tau_{part} = (10 \times 10^{-7})\ p\ Q_{part}, \text{ and}$$

$$\tau_{NO_2} = (1.7 \times 10^{-7})\ p\ Q_{NO_x}$$

These yielded:

		Phase I	Phase II	Phase III
τ_{part}	=	0.017	0.065	0.126
τ_{NO_2}	=	0.025	0.082	0.148

Background Visual Range. A background visual range (r_{VO}) of 170 km for the study region was obtained from the mapped values given in the EPA Visibility Workbook.

Optical Thickness for Primary and Secondary Aerosol. The optical thickness parameter was then calculated for primary and secondary aerosol. For this calculation, total SO_2 and particulate emissions from all WRSP sources were used giving:

$$\tau_{aerosol} = (1.06 \times 10^{-5})(r_{VO})(Q_{part} + 1.31\ Q_{SO_2})$$

		Phase I	Phase II	Phase III
$\tau_{aerosol}$	=	0.005	0.010	0.016
where Q_{SO_2}	=	1.41	2.36	3.25 metric tons/day
Q_{part}	=	0.93	2.41	4.72 metric tons/day

Optical Contrast. Finally, optical contrast was calculated for the plume against the sky as background (C_1), the plume against the terrain as

background (C_2), and the change in sky-terrain contrast caused by primary and secondary aerosol (C_3). For these, the formulas are:

$$C_1 = -\frac{\tau_{NO_2}}{\tau_{part} + \tau_{NO_2}} \left[1 - \exp\left(-\tau_{part} - \tau_{NO_2}\right)\right]\left[\exp\left(-0.78\ X/r_{VO}\right)\right] ,$$

$$C_2 = \left[1 - \left(\frac{1}{C_1 + 1}\right) \exp\left(-\tau_{part} - \tau_{NO_2}\right)\right]\left[\exp\left(-1.56\ X/r_{VO}\right)\right] ,$$

$$C_3 = 0.368 \left[1 - \exp\left(-\tau_{aerosol}\right)\right] .$$

These gave the following contrast values at Dinosaur National Monument for Phases I and III of the proposed project:

		Phase I	Phase II	Phase III
C_1	=	-0.019	-0.059	-0.101
C_2	=	0.013	0.049	0.093
C_3	=	0.002	0.004	0.006

Since the absolute values of C_1, C_2, and C_3 are all less than or very close to 0.10, significant visibility impairment in Class I areas is unlikely.

8.3 VEGETATION AND SOILS

8.3.1 Soil Types Occurring in the Area

The soil associations that occur in Tracts Ua and Ub are No. 51 and No. 63, as classified by the Soil Conservation Service. Soils of Association No. 51 occur along the White River. At this site, they are Aquic Ustifluvents and constitute about 25 percent of Association No. 51. The remainder of the soils in the tracts are Typic Torriorthents, Lithic Calcionthids, and Lithic Natragids. For the major portion of the tracts, Torriorthent soils are more stony than indicated on regional soils maps, while the Natragid soils are less stony than indicated.

The soils of Tracts Ua and Ub consist of shallow to very shallow (less than 20 inches deep) soils on sloping to steep upland surfaces cut by numerous intermittent drainages and containing many areas of rock outcrops and rock escarpments.

Soils A, As, B, Bs, and F are included in these shallow sites. They consist of sandy loams, loams, channery sandy loams, and channery loams. The occurrence of coarse fragments (channers and flaggs) usually increases with depth, and numerous flagstones, with a small proportion of soil, may be found immediately above the bedrock. Surface soils are light-colored and moderately calcareous. The $CaCO_3$ (lime) content as a rule increases with depth and occurs as a coating on the undersides of rock fragments.

Numerous drainage courses are found throughout the tracts. Most of these have intermittent stream channels, and the soils along these channels are generally deep (more than 60 inches). The D soils occur in these areas and are most extensive in the Southam Canyon drainage area. They are mainly sandy loams or channery sandy loams, light-colored and moderately calcareous.

Along the Evacuation Creek drainage, the D soils are associated with N soils. The latter are deep, moderately fine textured, and strongly alkaline, with a high concentration of exchangeable sodium. The N soils also are found on stream terraces about 50 to 1,000 feet above the White River floodplain. In these areas the N soils occur with E soils. The E soils are deep, moderately coarse textured, with a strong $CaCO_3$ (lime) horizon in the subsoil.

W soils occur adjacent to the White River, mainly in the corridor outside Tracts Ua and Ub. These are deep, silty soils that are seasonablly wet in deeper horizons and generally have a high salt content.

8.3.2 Native Vegetation

The plant communities on the tracts are part of a widespread and diverse vegetative cover extending over the Uinta Basin. Published reports of the region, aerial photographs, and extensive reconnaissance indicate that the vegetation on the tracts can be grouped into four major types:

- Type 1: Sagebrush-greasewood
- Type 2: Juniper
- Type 3: Shadscale
- Type 4: Riparian

Plant species and percentage composition of each vegetation type are reported in Table 8-4. The relative abundance of each species is indicated by the percentage of the total plant coverage determined during the baseline sampling programs in 1974-1975. These estimates are representative of present plant species abundance, with the exception of annuals and grasses, which vary from year to year with weather and the degree of disturbance by livestock and wildlife. Cover was estimated within 25 percent of the annual or seasonal mean for most species, at the 90 percent level of significance.

The exceptions were those species that occurred infrequently, or whose cover attribute was variable and difficult to estimate.

Sagebrush-Greasewood. This vegetation type is found on deeper soils above the riparian type and below the juniper type. It is extensive and is found on both the broad valleys and canyon bottoms of about 25 percent of the tracts.

Juniper. This vegetation type is found at higher elevations, usually above 5,400 feet. This type consists of open, sparse stands of juniper mixed with a few pinyon pines (*Pinus edulis*) above 6,000 feet and big sagebrush in draws and valleys. The juniper type covers 35 to 40 percent of the tracts, but is found predominantly on the southern half of Tract Ua.

Table 8-4

PLANT SPECIES IN EACH OF THE PLANT COMMUNITIES

SAGEBRUSH-GREASEWOOD – VEGETATION TYPE 1

Species[a]	Common Name	Composition by Percent of Total Plant Coverage[d]
Fall 1974[c]		
Sarcobatus vermiculatus	Greasewood	22
Salsola kali	Russian Thistle	21
Artemisia tridentata	Big Sagebrush	17
Artemisia nova	Black Sagebrush	9
Grayia spinosa	Spiny Hop Sage	9
Crytograms	Lichens	6
Chrysothamnus viscidiflorus	Sticky Flower Rabbitbrush	5
Oryzopsis hymenoides	Indian Ricegrass	4
Atriplex confertifolia	Shadscale	2
Xanthocephalum sarothrae	Snakeweed	2
Tetradymia spinosa	Horsebrush	1
Others[b]		2
Spring 1975[c]		
Bromus tectorum	Cheatgrass	17
Boraginaceae	Borage Family	12
Grayia spinosa	Spiny Hop Sage	9
Chrysothamnus nauseousus	Rubber Rabbitbrush	9
Stipa comata	Needle-and-Thread Grass	7
Tetradymia spinosa	Horsebrush	6
Sarcobatus vermiculatus	Greasewood	6
Artemisia tridentata	Big Sagebrush	5
Oryzopsis hymenoides	Indian Ricegrass	3
Mentzelia albicaulis	Small-flowered Mentzelia	3
Chrysothamnus viscidiflorus	Sticky Flower Rabbitbrush	3
Opuntia spp.	Prickly-pear Cactus	2
Artemisia nova	Black Sagebrush	2
Atriplex confertifolia	Shadscale	2
Sitanion hystrix	Squirreltail Grass	2
Eurotia lanata	Winterfat	2
Cleome lutea	Pursh	1
Hilaria jamesii	Galleta Grass	1
Lithospermum ruderale	Puccoon	1
Sphaeralcea coccinea	Copper Mallow	1
Salsola kali	Russian Thistle	1
Artemisia spinescens	Bud Sagebrush	1
Others[b]		4

Table 8-4 (Continued)

JUNIPER – VEGETATION TYPE 2

Species[a]	Common Name	Composition by Percent of Total Plant Coverage[d]
Fall 1974[c]		
Juniperus osteosperma	Juniper	81
Artemisia nova	Black Sagebrush	8
Chrysothamnus viscidiflorus	Sticky Flower Rabbitbrush	2
Hilaria jamesii	Galleta Grass	2
Xanthocephalum sarothrae	Snakeweed	1
Atriplex confertifolia	Shadscale	1
Oryzopsis hymenoides	Indian Ricegrass	1
Others[b]		4
Spring 1975[c]		
Juniperus osteosperma	Utah Juniper	56
Sarcobatus vermiculatus	Greasewood	7
Chrysothamnus nauseosus	Rubber Rabbitbrush	5
Stipa comata	Needle-and-Thread Grass	4
Hilaria jamesii	Galleta Grass	4
Artemisia tridentata	Big Sagebrush	3
Hedysarum boreale	Sweetvech	3
Hymenoxys scaposa	Hymenoxys	2
Chrysothamnus greeni	Rabbitbrush	2
Artemisia nova	Black Sagebrush	2
Ephedra virdis	Mormon Tea	2
Oryzopsis hymenoides	Indian Ricegrass	2
Phacelia spp.	Phacelia	1
Boraginaceae	Borage Family	1
Atriplex confertifolia	Shadscale	1
Leptodactylon watsonii	Leptodactylon	1
Chenopodium album	Goosefoot	1
Others[b]		3

Table 8-4 (Continued)

SHADSCALE – VEGETATION TYPE 3

Species[a]	Common Name	Composition by Percent of Total Plant Coverage[d]
Fall 1974[c]		
Artemisia tridentata	Big Sagebrush	33
Atriplex confertifolia	Shadscale	32
Artemisia nova	Black Sagebrush	12
Hilaria jamesii	Galleta Grass	4
Sarcobatus vermiculatus	Greasewood	4
Tetradymia spinosa	Horsebrush	3
Salsola kali	Russian Thistle	2
Xanthocephalum sarothrae	Snakeweed	2
Crytograms	Rock Brakes	2
Chrysothamnus viscidiflorus	Sticky Flower Rabbitbrush	1
Others[b]		5
Spring 1975[c]		
Bromus tectorum	Cheatgrass	21
Chrysothamnus viscidiflorus	Sticky Flower Rabbitbrush	11
Chrysothamnus greeni	Rabbitbrush	9
Artemisia tridentata	Big Sagebrush	8
Chorispora tenella	Blue Mustard	7
Hilaria jamesii	Galleta Grass	6
Tetradymia spinosa	Horsebrush	6
Sarcobatus vermiculatus	Greasewood	5
Atriplex confertifolia	Shadscale	4
Opuntia spp.	Prickly-pear Cactus	2
Eriogonum effusum	Wild Buckwheat	2
Sporbolus airoides	Alkali Sacaton	2
Stipa comata	Needle-and-Thread Grass	2
Artemisia spinescens	Bud Sagebrush	2
Suaeda torreyana	Sea-blite	2
Sitanion hystrix	Squirreltail Grass	1
Xanthocephalum sarothrae	Snakeweed	1
Suaeda spp.	Sea-blite	1
Oenothera caespitosa	White Stemless Evening Primrose	1
Eurotia Lanata	Winterfat	1
Halogeton glomeratus	Halogeton	1
Oryzopsis hymenoides	Indian Ricegrass	1
Eriogonum spp.	Wild Buckwheat	1
Cruciferae	Mustard family	1
Sphaeralcea coccinea	Scarlet Mallow	1
Others[b]		1

RIPARIAN – VEGETATION TYPE 4

Species[a]	Common Name	Composition by Percent of Total Plant Coverage[d]
Fall 1974[c]		
Populus fremontii	Cottonwood	46
Tamarix pentandra	Salt Cedar	17
Chrysothamnus viscidiflorus	Sticky Flower Rabbitbrush	12
Distichlis stricta	Saltgrass	6
Sarcobatus vermiculatus	Greasewood	5
Chrysothamnus nauseosus	Big Rabbitbrush	4
Xanthocephalum sarothrae	Snakeweed	2
Artemisia tridentata	Big Sagebrush	2
Saliz exigua	Willow	1
Salsola kali	Russian Thistle	1
Agropyron smithii	Western Wheatgrass	1
Others[b]		3
Spring 1975[c]		
Populus fremontii	Cottonwood	28
Bromus tectorum	Cheatgrass	15
Sarcobatus vermiculatus	Greasewood	12
Salix spp.	Willow	9
Tamarix pentandra	Salt Cedar	5
Chrysothamnus viscidiflorus	Sticky Flower Rabbitbrush	4
Chrysothamnus nauseosus	Rubber Rabbitbrush	3
Kochia spp.	Burning-bush	3
Melilotis officinalis	Sweet-clover	2
Poa pratensis	Kentucky Bluegrass	2
Distichlis spicata	Saltgrass	2
Chrysothamnus greeni	Rabbitbrush	2
Lepidium spp.	Peppergrass; Pepperweed	1
Distichlis stricta	Saltgrass	1
Cleome lutea	Pursh	1
Sporobolus airoides	Alkali Sacaton	1
Atriplex canescens	Fourwing Saltbrush	1
Ambrosia psilostachya	Western Ragweed	1
Agropyron smithii	Western Wheatgrass	1
Iva axillaris	Marsh Elder	1
Others[b]		5

(a) Taxonomy after Harrington (Ref. 2-18) and Holmgren and Reveal (Ref. 2-19).

(b) This group includes the annuals and grasses. The abundance is subject to change from year to year depending upon the favorability of weather and degree of disturbance by animals (wildlife and livestock).

(c) Extensive botanical sampling performed only during baseline surveys (1974-1975); subsequent studies (1976-present) emphasized specific parameters such as production of biomass of dominant species.

(d) Total plant coverage (100 percent) may vary in area from season to season or year to year. Comparisons of composition, in percent, should only be made between similar seasons (e.g., Fall 1974 with Fall 1975).

Shadscale. This vegetation type is found on shallow soils of south- and west-facing slopes and along ridgetops where soil depth is less than 18 inches. The most extensive portion is found on Tract Ub on either side of Evacuation Creek. Approximately 29 percent (about 3,000 acres) of the tracts are covered by the shadscale type.

Riparian. This vegetation type is found along stream courses and river bottoms. Only two on-tract areas are classified as riparian: the borders of Evacuation Creek and the floodplain of the White River. The soils of the narrow Evacuation Creek bottom lands are considerably more saline than those of the White River. The riparian type constitutes approximately 2 percent (about 240 acres) of the vegetation on the project area.

Most of the annual species mature in the spring when soil moisture is favorable. Perennial grasses mature in early summer, while shrubs grow and produce seeds over an extended period of time, ranging from June for spiney horsebrush to October for shadscale.

When considered from a regional viewpoint, the sagebrush, greasewood, and shadscale vegetation types on site are a part of plant associations extending to the north and west for 30 to 60 miles. Similarly, the juniper vegetation type found on Tracts Ua and Ub (about 4,500 acres) continue into the southern and eastern portions of the Uinta Basin for 20 to 30 miles. Ecologically equivalent plant communities may be found in parts of the Colorado Plateau and the Great Basin.

8.3.3 Air Pollution Impact on Soils and Vegetation

Direct impacts on soils and vegetation are expected to be highly localized. Localized direct impacts to soils and vegetation will occur in Southam Canyon as a result of deposition of processed shale. Outside the Southam Canyon disposal area, road dust distributed by wind and airborne emissions released by retorting, internal combustion engines, and steam generation could potentially affect soils and vegetation in the immediate vicinity of the facility.

To protect soils and vegetation from air pollution damage, secondary National Ambient Air Quality Standards (NAAQS) were established by the federal government. As shown in Section 7, concentrations of criteria pollutants are predicted to be well below the secondary NAAQS. Conversion products such as SO_4, NO_3, and H_2SO_4 are also expected to be minimal. Therefore, damage to vegetation and soils is not likely to result from project airborne emissions. No species having significant commercial or recreational value are anticipated to be affected.

REFERENCES — SECTION 8

8-1 Utah Implementation Plan, State of Utah, Department of Social Services, Division of Health, 1972.

8-2 Workbook for Estimating Visibility Impairment, U.S. EPA, Office of Air Quality Planning and Standards, EPA-450/4-80-031, November 1980.

8-3 D.B. Turner, Workbook of Atmospheric Dispersion Estimates, U.S. Department of Health, Education, and Welfare, Public Health Service Publication No. 999-AP-26, 1969.

ABBREVIATIONS

ANFO	Ammonium nitrate — fuel oil
^{o}API	Degrees American Petroleum Institute
ASTM	American Society for Testing and Materials
AV	AeroVironment Inc.
BACT	Best Available Control Technology
BPD	Barrels per day
BPSD	Barrels per stream day
Btu	British thermal unit
C	Degrees Celsius
CFH	Cubic feet per hour
cfm	Cubic feet per minute
CFR	Code of Federal Regulations
cfs	Cubic feet per second
CH_4	Methane
cm	Centimeter
CO	Carbon monoxide
CO_2	Carbon dioxide
CS	Centistokes
DCM-OS	Deputy Conservation Manager — Oil Shale
DDP	Detailed Development Plan
DH	Direct-heated
EP	End point
EPA	Environmental Protection Agency
F	Degrees Fahrenheit
FID	Flame ionization detector
ft	Feet
ft^3	Cubic feet
gal	Gallons
GC	Gas chromatography

GEP	Good engineering practice
g/m^2	Grams per square meter
g/sec	Grams per second
H_2	Hydrogen
HC	Hydrocarbons
HHV	Higher heating value
hp	Horsepower
hr	Hour
H_2S	Hydrogen sulfide
IBP	Initial boiling point
IH	Indirect-heated
K	Kelvin
km	Kilometer
lb	Pound
lb/day	Pounds per day
lb/hr	Pounds per hour
m	Meter
M	Thousand
mb	Millibar
mg/m^3	Milligrams per cubic meter
mi	Miles
mm	Millimeter
MM	Million
m/sec	Meters per second
mph	Miles per hour
MSL	Mean sea level
MST	Mountain standard time
MW	Megawatt
N_2	Nitrogen
NAAQS	National Ambient Air Quality Standards
NESHAP	National Emission Standards for Hazardous Air Pollutants
NH_3	Ammonia
NMHC	Nonmethane hydrocarbons

NO_x	Oxides of nitrogen
NO_2	Nitrogen dioxide
NRC	Nuclear Regulatory Commission
NSPS	New Source Performance Standards
O_3	Ozone
OSEAP	Oil Shale Environmental Advisory Panel
OSO	Oil Shale Office
OSHA	Occupational Safety and Health Administration
p	Plume dispersion parameter
ppb	Parts per billion
ppm	Parts per million
ppmv	Parts per million volume
ppmw	Parts per million weight
PSD	Prevention of Significant Deterioration
Q	Total mass emission rate
r_{vo}	Background visual range
R	Range
SCFM	Standard cubic feet per minute
SCFSD	Standard cubic feet per stream day
SD	Stream day
SO_2	Sulfur dioxide
STPSD	Short tons per stream day
T	Tons (2,000 pounds)
THC	Total hydrocarbons
TPD	Tons per day
TPH	Tons per hour
TPSD	Tons per stream day
TSP	Total suspended particulates
UBAQ	Utah Bureau of Air Quality
USGS	United States Geological Survey
UTM	Universal transverse mercator
vol %	Volume percent
WRSP	White River Shale Project
wt %	Weight percent

X	Distance from emissions source to Class I area
ΔT	Temperature change
μ	Micron
$\mu g/m^3$	Micrograms per cubic meter
σ_ω	Standard deviation of wind direction (vertical)
σ_θ	Standard deviation of wind direction (lateral)
σ_y	Standard deviation of crosswind direction
σ_z	Standard deviation of vertical wind direction
τ	Horizontal optical thickness

GLOSSARY

Acid Gas. The hydrogen sulfide and carbon dioxide found in natural and refinery gases which form acids when combined with moisture; these are known as sour acids when hydrogen sulfide or mercaptans are present.

Alluvium. Clay, silt, sand, gravel, or similar unconsolidated detrital material deposited during comparatively recent geologic time by running water.

Amine. One of a class of organic compounds which can be considered to be derived from ammonia by replacement of one or more hydrogen atoms by organic radicals.

Amine gas-treating unit. A unit that absorbs and removes acid gas from product gas by contacting the product gas with an aqueous solution of amine.

Aquifer. A geologic formation, group of formations, or part of a formation that contains sufficient saturated permeable material to yield significant quantities of water to wells and springs.

Baseflow. Sustained or fair-weather flow of a stream, whether or not it is affected by the works of man.

Biota. The collective flora and fauna of any particular area.

Bottoms. Oil, water, and foreign matter that collects in the bottom of storage tanks.

C_5+ Shale oil. Components of shale oil and gas with five or more carbon atoms per molecule.

Channery. Soils that contain fragments of flat sandstone, limestone, or schist up to 6 inches along the long axis.

Claus sulfur plant. A plant that converts hydrogen sulfide in a gas stream into elemental sulfur by means of solid catalysts.

Coke. A coherent, cellular, solid residue remaining from the destructive distillation of a coking coal, petroleum, or other carbonaceous material.

Coking. Destructive distillation of coal to make coke; a process for thermally converting the heavy residual bottoms of crude oil to lower-boiling-point petroleum products and by-product petroleum coke (thermal cracking for the conversion of heavy, low-grade oils into lighter products and a residue of coke).

Cryptogam. Non-seed-forming plant, such as fungi, lichen, and moss.

Cubic foot per second. The rate of discharge representing a volume of 1 cubic foot passing a given point during 1 second and is equivalent to approximately 7.48 gallons per second or 448.8 gallons per minute or 0.02832 cubic meter per second.

Cut-and-fill. A process for leveling land (to build roads, etc.) in which higher elevation land is removed and placed in lower elevation land to create a flat surface.

Dawsonite. A mineral consisting of a basic aluminum sodium carbonate.

Decommissioning. The suspension by the lessee of the work programs or the further processing of shale, without dismantling or destroying improvements.

Direct-heated mode. A method of imparting heat to the shale by direct contact heat transfer with gases formed in a combustion zone inside a retort.

Drainage area. An area, measured in a horizontal plane, enclosed by a topographic divide from which direct surface runoff from precipitation normally drains by gravity into a stream above a specified point.

Drainage basin. A part of the surface of the earth that is occupied by a drainage system, which consists of a surface stream or body of impounded surface water together with all tributary surface streams and bodies of impounded surface water.

Feed. Raw material that is fed into and processed in a unit.

Feed gas. Gas that is fed into and processed in a unit.

Fines. Smaller particles of oil shale coming out of the mine or from the crushing operation. Fines are generally ½-inch and under and must be removed from the feed of certain retort systems.

Fischer assay. A tentative ASTM standard laboratory method for expressing the potential amount of oil able to be derived from shale by pyrolysis. The results are expressed as gallons of oil per ton of oil shale.

Flaggy. Soils that contain relatively thin fragments 6 to 15 inches long of sandstone, limestone, slate, or shale (or rarely schist). A single piece is a flagstone.

Flue gas. The gaseous product of the combustion of any fuel passed to the atmosphere through a stack, chimney, or vent.

Fugitive dust. Colloidal-sized particulate matter generated incidentally by human activities.

Gas treating. Removing nonhydrocarbon impurities (such as ammonia, hydrogen sulfide, or carbon dioxide) from product gas.

Gilsonite. A black lustrous asphalt occurring especially in Utah (trademark).

High-Btu gas. A high-heating-value gas. The product gas from indirect-heated retorting is a high-Btu gas.

Hydrocarbon. An organic compound containing only carbon and hydrogen.

Hydrotreating. An oil refinery catalytic process in which petroleum intermediates, or product streams, is contacted with hydrogen to remove imputities such as oxygen, sulfur, nitrogen, or unsaturated hydrocarbons.

Hydrostabilization. A mild hydrotreating process that uses less hydrogen than the hydrotreating process.

Indirect-heated mode. A method of imparting heat to the shale by an externally heated circulating gas stream.

In situ. Derived from the Latin term meaning "in place." With reference to oil shale, it describes a method of underground retorting where the oil is recovered and the shale residue is left in the ground.

Kerogen. The organic portion of oil shale. It decomposes when heated (to about 900F) to form synthetic oil and gaseous products.

Leachate. A solution or product obtained by leaching.

Light ends. The lower-boiling-point components of a mixture of hydrocarbons, such as those evaporated or distilled off easily in comparison with the bulk of the mixture; for hydrocarbon mixtures, this is usually considered to be butane or lighter.

Loam. Textured class name for soils having 7 to 27 percent clay, 28 to 50 percent silt, and less than 52 percent sand.

Low-Btu gas. A gas with a low heating value. The product gas from direct-heated retorting is a low-Btu gas.

Marlstone. A rock consisting of approximately equal amounts of carbonate and clay. Oil shale is basically a marlstone.

Micrograms per liter. A unit for expressing the concentration of chemical constituents in solution as mass (micrograms) of solute per unit volume (liter) of water. One thousand micrograms per liter is equivalent to one milligram per liter.

Milligrams per liter. A unit for expressing the concentration of chemical constituents in solution. Milligrams per liter represents the mass of solute per unit volume (liter) of water. Concentration of suspended sediment also is expressed in mg/l and is based on the mass of sediment per liter of water-sediment mixture.

Mining panel. In the room-and-pillar method, a large area in the mine in which many pillars are left to support the roof.

Nahcolite. The mineral sodium bicarbonate. It is potentially commercially valuable for removing sulfur from flue gases.

Oil shale. Laminated sedimentary rock deposits containing both mineral and organic matter, principally kerogen.

Oil shale deposit centroid. The center of mass of the oil shale, as determined by geological studies.

Particulates. Solid materials generated by processes and emitted from a discrete source (see "fugitive dust").

Petroleum naphtha. A low-boiling-point range hydrocarbon liquid mixture.

Phase I. The phase during which two commercial-sized retorts of IH and DH types, along with a working mine and ancillary facilities, are developed.

Phase II. The first of two commercial operation phases, where Phase I production capacity is increased by construction of additional retorts, expanded mining, and additional ancillary facilities.

Phase III. The second of two commercial operation phases characterized by further facilities construction and culminating in the ultimate production capacity of the project.

Phase I retention dam (catchment). A dam built during Phase I adjacent to the processed shale pile, the purpose of which is to intercept runoff and leachate from the Phase I processed shale pile.

Pour point. The lowest temperature (determined by laboratory procedure) at which a liquid hydrocarbon will remain fluid enough to be poured.

Pour point depressant. An additive that lowers the pour point of an oil.

Processed shale. The residue shale from the retorting operation. It is normally 80 to 85 percent by weight of the original oil shale material.

Product gas. The usable gas emitted from the direct-heated or indirect-heated retort during the retorting of shale oil.

Pyrolysis. Chemical change brought about by the action of heat, in the absence of combustion.

Reforming. A general term used for various thermal or catalytic conversions of petroleum, such as cracking, polymerization, dehydration, and isomerization.

Retort. The pyrolysis kiln in which raw oil shale is retorted.

Retorting. The process in which the kerogen in oil shale is converted by heating to oil and gas.

Room and pillar. An underground mining technique in which a room is mined out and a pillar is left for mine support.

Room. The opening in a mine between pillars.

Sandy loam. Soil of the sandy loam class that has 50 percent sand and less than 20 percent clay.

Shale oil. A viscous organic liquid product produced from retorting oil shale.

Slurry. A two-phase liquid-solid mixture.

Solute. Any substance that is dissolved in water (or other solvent) forming a solution.

Sour gas. A gas mixture that contains hydrogen sulfide or mercaptans.

Sour water. Water containing hydrogen sulfide or mercaptans.

Sour water stripping. Removing hydrogen sulfide from sour water.

Southam Canyon retention dam. A dam built during Phase II at the mouth of Southam Canyon, the purpose of which is to intercept processed shale runoff and leachate and hence prevent them from reaching the White River.

Specific conductance. A measure of the ability to conduct an electrical current, usually expressed in micromhos per centimeter at 25 degrees Celsius. Specific conductance is related to the type and concentration of ions in solution and can be used for approximating the dissolved-solids concentration in water. Commonly, dissolved solids (in milligrams per liter) account for about 65 percent of the specific conductance (in micromhos) of common streams. The relation is not constant from stream to stream or from well to well, and it may even vary in the same source with changes in the composition or concentration of dissolved components.

Stope. An underground excavation from which the ore has been extracted, in a series of steps.

Storage silo. A circular vessel, usually having a conical bottom section, that is used for storing solids in bulk quantities.

Stretford sulfur unit. A specific trade-name plant that removes hydrogen sulfide in a gas stream and converts it to elemental sulfur.

Surge bin. A storage vessel that holds enough material to provide a steady supply to a downstream user or process.

Suspended-sediment load. The quantity of suspended sediment passing a section in a specified period.

Tail gas. Waste gas from a sulfur-treating plant.

Tail gas treating. Removing sulfur from tail gas.

Tank farm. An area containing large storage tanks for oil or other liquids.

Train. A processing system comprising a series of processing units.

Transect. A sample area (as of vegetation), usually in the form of a long continuous strip.

Tuff. A rock composed of the finer kinds of volcanic detritus, usually fused together by heat.

Upgrading. The various process combinations employed to improve the quality of the oil.

Wet scrubber. A vessel in which spray liquid is used to absorb solid particulates and remove them from circulating gases.

APPENDICES

Appendix A

EMISSION CALCULATIONS FOR CRITERIA POLLUTANTS

Appendix A contains all emission calculations for Phases I, II and III. Annual emission estimates are reduced by a factor of 0.9 where appropriate to allow for outage and maintenance.

A.1 PHASE I PARTICULATE, SO_2, NO_x, CO, AND HC EMISSIONS

I-1a. MINING

Particulate:

EF = 0.018 lb/t (Ref. A-1)

Control efficiency = 80% (Wet suppression and settling) (Ref. A-1)

Q = (30,000 t/day)(0.018 lb/t)(1 - 0.8)

Q = 108 lb/day = 17.7 t/yr

I-1b. BLASTING

Carbon Monoxide:

EF = 0.022 lb/lb ANFO (Ref. A-1)

Q = (18,000 lb ANFO/day)(0.022 lb/lb ANFO)

Q = 396 lb/day = 65.0 t/yr

Nitrogen Oxides:

EF = 0.012 lb/lb-ANFO (Ref. A-1)

Q = (18,000 lb ANFO/day)(0.012 lb/lb ANFO)

Q = 216 lb/day = 35.5 t/yr

I-1c. DIESEL FUEL COMBUSTION

Particulate:

EF = 22 lb/1,000 gal (Ref. A-2)

Q = (5,000 gal/day)(22 lb/1,000 gal)

Q = 110 lb/day = 18.1 t/yr

Carbon Monoxide:

EF = 90 lb/1,000 gal (Ref. A-2)

Q = (5,000 gal/day)(90 lb/1,000 gal)

Q = 450 lb/day = 73.9 t/yr

Hydrocarbons:

EF = 28 lb/1,000 gal (Ref. A-2)

Q = (5,000 gal/day)(28 lb/1,000 gal)

Q = 140 lb/day = 23.0 t/yr

Nitrogen Oxides:

EF = 428 lb/1,000 gal (Ref. A-2)

Q = (5,000 gal/day)(428 lb/1,000 gal)

Q = 2,140 lb/day = 351.5 t/yr

Sulfur Dioxide:

EF = 31 lb/1,000 gal (Ref. A-2)

Q = (5,000 gal/day)(31 lb/1,000 gal)

Q = 155 lb/day = 25.5 t/yr

I-2a. IN-MINE CRUSHING (PRIMARY)

Particulate:

EF = 0.02 lb/t (Ref. A-3)

Control efficiency = 80% (Wet suppression and settling) (Ref. A-1)

Q = (15,000 t/day)(0.02 lb/t) (1 - 0.8)

Q = 60 lb/day = 9.9 t/yr

I-2b. IN-MINE CRUSHING (SECONDARY)

Particulate:

Inlet grain loading = 6 gr/scf (Ref. A-4)

Control efficiency = 99.7% (Baghouse) (Ref. A-2)

Outlet grain loading = (6 gr/scf) (1 - 0.997) = 0.018 gr/scf

Q = (5,000 scfm)(0.018 gr/scf)(60 min/hr)(lb/7,000 gr)

Q = 0.77 lb/hr = 18.5 lb/day = 3.0 t/yr

I-3. MINE CONVEYOR SURGE BIN

Particulate:

Inlet grain loading = 4 gr/scf (Ref. A-4)

Control efficiency = 99.7% (Baghouse) (Ref. A-2)

Outlet grain loading = (4 gr/scf) (1 - 0.997) = 0.012 gr/scf

Q = (5,000 scfm)(0.012 gr/scf)(60 min/hr)(lb/7,000 gr)

Q = 0.5 lb/hr = 12.3 lb/day = 2.0 t/yr

I-4. STORAGE SILO FEED

Particulate:

Inlet grain loading = 4 gr scf (Ref. A-4)

Control efficiency = 99.7% (Baghouse) (Ref. A-2)

Outlet grain loading = (4 gr/scf) (1 - 0.997)

= 0.012 gr/scf

Q = (5,000 scfm)(0.012 gr/scf)(60 min/hr)(lb/7,000 gr)

Q = 0.5 lb/hr = 12.3 lb/day = 2.0 t/yr

I-5. SURFACE CRUSHING AND SCREENING

Particulate:

Inlet grain loading = 7 gr/scf (Ref. A-4)

Control efficiency = 99.7% (Baghouse) (Ref. A-2)

Outlet grain loading = (7 gr/scf) (1 - 0.997) = 0.021 gr/scf

Q = (15,000 scfm)(0.021 gr/scf)(60 min/hr)(lb/7,000 gr)

Q = 2.7 lb/hr = 64.8 lb/day = 10.6 t/yr

I-6. FINES CONVEYOR FEED

Particulate:

$$EF = \frac{0.0018\ (S/5)(U/5)}{(M/2)^2}$$ (Ref. A-5)

S = 15% silt (estimated)

U = 10 mph

M = 1% moisture (estimated)

$$EF = \frac{0.0018\ (15/5)(10/5)}{(1/2)^2} = 0.04\ lb/t$$

Control efficiency = 90% (Wet Suppression) (Ref. A-5)

Q = (2,730 t/day)(0.04 lb/t) (1 - 0.9)

Q = 10.9 lb/day = 1.8 t/yr

I-7. FINES CONVEYOR TRANSFER POINTS

Particulate:

EF = 0.04 lb/t (see #I-6)

Control efficiency = 90% (see #I-6)

Q = (2,730 t/day) (0.04 lb/t) (1 - 0.9) = 10.9 lb/day each

Three transfer points

Q = (10.9 lb/day)(3) = 32.7 lb/day = 5.4 t/yr

I-8. FINES CONVEYOR DISCHARGE TO STACKER

Particulate:

EF = 0.04 lb/t (see #I-6)

Control efficiency = 90% (see #I-6)

Q = (2,730 t/day) (0.04 lb/t) (1 - 0.9)

Q = 10.9 lb/day = 1.8 t/yr

I-9. UNION CONVEYOR FEED

Particulate:

$$EF = \frac{0.0018\ (S/5)(U/5)}{(M/2)^2}$$ (Ref. A-5)

S = 2% silt (estimated)

U = 10 mph

M = 1% moisture (estimated)

$$EF = \frac{0.0018\ (2/5)(10/5)}{(1/2)^2} = 0.006\ lb/t$$

Control efficiency = 90% (Wet suppression) (Ref. A-5)

Q = (11,600 t/day)(0.006 lb/t) (1 - 0.9)

Q = 7 lb/day = 1.1 t/yr

I-10. UNION RETORT FEED SILO

Particulate

Inlet grain loading = 3 gr/scf (Ref. A-4)

Control efficiency = 99.7% (Baghouse) (Ref. A-2)

Outlet grain loading = (3 gr/scf) (1 - 0.997)

= 0.01 gr/scf

Q = (1,000 scfm)(0.01 gr/scf)(60 min/hr)(lb/7,000 gr)

Q = 0.09 lb/hr = 2.1 lb/day = 0.34 t/yr

I-11. SUPERIOR CONVEYOR FEED

Particulate:

$$EF = \frac{0.0018\ (S/5)(U/5)}{(M/2)^2}$$ (Ref. A-5)

S = 2% silt (estimated)

U = 10 mph

M = 1% moisture (estimated)

$$EF = \frac{0.0018\ (2/5)(10/5)}{(1/2)^2} = 0.006\ lb/t$$

Control efficiency = 90% (Wet suppression) (Ref. A-5)

Q = (13,000 t/day)(0.006 lb/t) (1 - 0.9)

Q = 7.8 lb/day = 1.3 t/yr

I-12. SUPERIOR RETORT FEED

Particulate:

Inlet grain loading = 3 gr/scf (Ref. A-4)

Control efficiency = 99.7% (Baghouse) (Ref. A-2)

Outlet grain loading = (3 gr/scf) (1 - 0.997)

= 0.01 gr/scf

Q = (8,200 scfm)(0.01 gr/scf)(60 min/hr)(lb/7,000 gr)

Q = 0.70 lb/hr = 16.9 lb/day = 2.8 t/yr

I-13. UNION RETORT DISCHARGE TO PROCESSED SHALE CONVEYOR

Particulate:

$$EF = \frac{0.0018\ (S/5)(U/5)}{(M/2)^2}$$ (Ref. A-5)

S = 20% silt (estimated)

U = 10 mph

M = 20% moisture (estimated)

$$EF = \frac{0.0018\ (20/5)(10/5)}{(20/2)^2} = 0.0001\ lb/t$$

Q = (9,875 t/day)(0.0001 lb/t)

Q = 1 lb/day = 0.2 t/yr

I-14. SUPERIOR RETORT DISCHARGE TO PROCESSED SHALE CONVEYOR

Particulate:

EF = 0.0001 lb/t (see #I-13)

Q = (11,000 t/day)(0.0001 lb/t)

Q = 1 lb/day = 0.2 t/yr

I-15. PROCESSED SHALE CONVEYOR DISCHARGE TO BIN

Particulate:

$$EF = \frac{0.0018\ (S/5)(U/5)}{(M/2)^2}$$ (Ref. A-5)

S = 20% silt (estimated)

U = 10 mph

M = 15% moisture (estimated)

$$EF = \frac{0.0018\ (20/5)(10/5)}{(15/2)^2} = 0.0003\ lb/t$$

Q = (20,875 t/day)(0.0003 lb/t)

Q = 6.3 lb/day = 1.0 t/yr

I-16a. LOAD-IN TO COARSE SHALE STOCKPILE

Particulate:

Load-in via stacker.

$$EF = \frac{0.0018\ (S/5)(U/5)(H/10)}{(M/2)^2}$$ (Ref. A-5)

S = 3% silt (estimated)

U = 10 mph

H = 10 ft drop

M = 1% moisture (estimated)

$$EF = \frac{0.0018\ (3/5)(10/5)(10/10)}{(1/2)^2} = 0.009\ lb/t$$

Control efficiency = 75% (Lowering well) (Ref. A-5)

Q = (810 t/day)(0.009 lb/t) (1 - 0.75)

Q = 1.8 lb/day = 0.3 t/yr

I-16b. GROOMING OF COARSE SHALE STOCKPILE

Particulate:

Using a stacker for load-in and under-the-pile reclaim, very little mobile equipment will be necessary for grooming. The emission factor for grooming is determined by:

EF = 0.1(K)(S/1.5)(d/235) (Ref. A-5)

K = 0.1, little vehicular activity

S = 3% silt (estimated)

d = 275 dry days/yr

EF = 0.1(0.1)(3/1.5)(275/235) = 0.02 lb/t

Q = (810 t/day)(0.02 lb/t) = 16 lb/day

This is worst daily rate. Watering will achieve 50 percent control on an annual basis.

Q = (16 lb/day)(1 - 0.5) = 8 lb/day = 1.3 t/yr

I-16c. WIND EROSION

Particulate:

Maximum size of stockpile will be approximately 500,000 tons (3.6 acres). Wind erosion emissions are determined by:

$EF = 0.05\ (S/1.5)(D/90)(d/235)(f/15)$ (Ref. A-5)

S = 3% silt (estimated)

D = 365 days storage

d = 275 dry days/yr

f = 10% (wind speed exceeds 12 mph 10% of the time)

$EF = 0.05\ (3/1.5)(365/90)(275/235)(10/15) = 0.32$ lb/t-yr (uncontrolled)

Approximately 65 percent of the pile will be dead storage and will be coated to prevent degradation and wind erosion. At least 95 percent control is expected to be achieved. For dead storage wind erosion:

$Q = (500{,}000\ t)(0.65)(0.32\ lb/t\text{-}yr)(1 - 0.95)$

$Q = 2.6\ t/yr = 14\ lb/day$

The remaining 35 percent of the pile will be live. For live storage wind erosion:

$Q = (500{,}000\ t)(0.35)(0.32\ lb/t\text{-}yr)(yr/365\ days)$

$Q = 153\ lb/day$ (when watering not possible)

On an annual basis, 50 percent control will be achieved by watering.

$Q = (153\ lb/day)(0.5)(365\ days/yr)(t/2{,}000\ lb)$

$Q = 14\ t/yr$

Total from wind erosion:

$Q = 14\ lb/day + 153\ lb/day = 167\ lb/day$

$Q = 2.6\ t/yr + 14\ t/yr = 16.6\ t/yr$

I-16d. RECLAIM

Emergency reclaim is accomplished using the under-the-pile reclaim system. When it is necessary to reclaim, any dust generated by this operation will be offset by the stop of routine operations.

I-17a. LOAD-IN TO FINES STOCKPILE

Particulate:

Load-in by means of portable stacker conveyor.

$$EF = \frac{0.0018\ (S/5)(U/5)(H/10)}{(M/2)^2}$$ (Ref. A-5)

S = 15% silt (estimated)

U = 10 mph

H = 10 ft drop

M = 1% moisture (estimated)

$$EF = \frac{0.0018\ (15/5)(10/5)(10/10)}{(1/2)^2} = 0.04\ lb/t$$

Daily fines throughput = 2,730 t/day

Control efficiency = 90 % (Wet suppression) (Ref. A-5)

Q = (2,730 t/day)(0.04 lb/t)(0.1)

Q = (11 lb/day) = 1.8 t/yr

I-17b. FINES STOCKPILE GROOMING

Particulate:

EF = 16 lb/scraper-hour (Ref. A-6)

Eight (8) scraper-hours/day are estimated to be required.

Q = (8 hrs/day)(16 lb/hr) = 128 lb/day

This is worst daily rate. Watering when practical will reduce emissions by 50 percent on an annual basis.

Q = (128 lb/day)(365 days/yr)(0.9)(t/2000 lb)(0.5) = 10.5 t/yr

I-17c. WIND EROSION OF FINES STOCKPILE

Particulate:

Since fines will be deposited and stored in a canyon-like area, only the surface of the stockpile will be exposed to the wind. Using an emission factor for exposed areas rather than for storage piles:

$$EF = \frac{3{,}400\ (e/50)(S/15)(f/25)}{(PE/50)^2} = \text{lb/acre-year}$$ (Ref. A-5)

e = 50 tons/acre-year (surface erodibility)

S = 15% silt (estimated)

f = 10%

PE = 23 (Thornthwaite's Precipitation-Evaporation Index) (Ref. A-2)

$$EF = \frac{3{,}400\ (50/50)(15/15)(10/25)}{(23/50)^2} = 6{,}427 \text{ lb/acre-year}$$

Estimated size of stockpile = 30 acres; only 5 acres are exposed. Remainder is sealed.

Q = (5 acres)(6,427 lb/acre-year)(t/2,000 lb) = 16.1 t/yr

Compaction and chemical dust suppressants will be used to provide an estimated 85 percent control. (Ref. A-6)

Q = (16.1 t/yr)(1 - 0.85) = 2.4 t/yr = 13.2 lb/day

I-18a. TRUCK LOADING OF PROCESSED SHALE

Particulate:

$$EF = \frac{0.0018\ (S/5)(U/5)}{(M/2)^2}$$ (Ref. A-5)

S = 20% silt (estimated)

U = 10 mph

M = 15% moisture content (estimated)

$$EF = \frac{0.0018\ (20/5)(10/5)}{(15/2)^2} = 0.0003\ lb/t$$

Throughput = 20,875 t/day

Q = (20,875 t/day)(0.0003 lb/t) = 6.3 lb/day

Q = 6 lb/day = 1 t/yr

I-18b. TRUCK DUMPING OF PROCESSED SHALE

(Eighty ton bottom dump trucks). Same emission factor as in 18a above.

EF = 0.0003 lb/t

Q = (20,875 t/day)(0.0003 lb/ton)

Q = 6.3 lb/day = 1 t/yr

I-18c. ROAD DUST

Particulate:

$EF = (0.6)(0.81s)(S/30)[(365 - W)/365]$ (Ref. A-6)

s = 12% silt (estimated)

S = 15 mph (truck speed)

W = 90 days with >0.01 in. rain

$EF = (0.6)(0.81)(12)(15/30)[(365 - 90)/365]$

EF = 2.2 lb/VMT

Haul roads will be chemically stabilized to achieve 85 percent control.

VMT = (20,875 t/day)(2 miles roundtrip)/(80 t/truck)

VMT = 522/day

Q = (522 VMT/day)(2.2 lb/VMT)(1 - 0.85)

Q = 772 lb/day = 28 t/yr

I-18d. WIND EROSION

Particulate:

Processed shale will be deposited in Southam Canyon whereby the sides of the spent shale pile will not be exposed to the wind, i.e., only the top surface will be subject to wind erosion. For surface areas, uncontrolled emissions can be estimated suing the following emission factor:

$$EF = \frac{3{,}400\ (e/50)(S/15)(f/25)}{(PE/50)^2}$$ (Ref. A-5)

e = 50 tons/acre-year (surface erodibility)

S = 20% silt (estimated)

f = 10% (estimated)

PE = 23

$$EF = \frac{3{,}400\ (50/50)(20/15)(10/25)}{(23/50)^2} = 8{,}570 \text{ lb/acre-year}$$

By the end of Phase I, the processed shale pile will cover an area of 130 acres. This area will be revegetated as the fill progresses, returning the area back to natural background levels. A maximum of about thirty (30) acres of processed shale will be exposed before revegetation.

Q = (30 acres)(8,570 lb/acre-year)(t/2,000 lb) = 129 t/yr

Q = (129 t/yr)(2,000 lb/t)(yr/365 days) = 704 lb/day

Compaction and chemical dust suppressants are expected to reduce wind erosion by 85 percent.

Q = (704 lb/day)(0.15) = 106 lb/day = 19 t/yr

I-18e. GROOMING AND COMPACTION

Particulate:

EF = 16 lb/scraper-hour (Ref. A-6)

Twenty-four (24) scraper-hours per day will be required.

Q = (24 hours/day)(16 lb/hour) = 384 lb/day

This is worst daily rate. Watering will be employed when practical to achieve 50 percent control on an annual basis.

Q =(384 lb/day)(0.5)(365 days/yr)(0.9 plant factor)(t/2,000) = 32 t/yr

I-19. UNION RECYCLE GAS HEATER

Heat input = 211 MMBtu/hr oil + 29 MMBtu/hr gas

Heat content oil = 6.09 MMBtu/Bbl

Heat content gas = 806 Btu/scf

Burn rate = (211 MMBtu/Hr)/(6.09 MMBtu/Bbl)
+ (29 MMBtu/Hr)/(806 Btu/Scf)
= 34.7 Bbl/hr + 36,000 scf/hr

Sulfur Dioxide:

For oil, EF = 142 S (lb/10^3 gal) (Ref. A-2)

S = 0.002% sulfur (design value)

EF = 142 (0.002) = 0.284 lb/10^3 gal

For gas, total sulfur content after treatment will be 0.49 gr/scf (including 0.1 gr/scf H_2S).

EF = (0.49 gr/scf)(10^6 scf/MMscf)(lb/7,000 gr)(64 lb-SO_2/32 lb-S)

= 140 lb/MMscf

Q = (35 Bbl/hr)(42 gal/Bbl)(0.284 lb/10^3 gal) +

(36,000 scf/hr)(140 lb/MMscf)

Q = 5.5 lb/hr = 131 lb/day = 21.5 t/yr

Hydrocarbons:

EF = 1 lb/10^3 gal + 3 lb/MMscf (Ref. A-2)

Q = (35 Bbl/hr)(42 gal/Bbl)(1 lb/10^3 gal) +
(3 lb/MMscf)(36,000 scf/hr)

Q = 1.6 lb/hr = 38 lb/day = 6.2 t/yr

Nitrogen Oxides:

For oil, $EF = 22 + 400\ (N)^2$ (Ref. A-2)

$N = 0.15\%$ by wt (design value)

$EF = 22 + 400(0.15)^2 = 31\ lb/10^3\ gal$

For gas, $EF = 210\ lb/MMscf$ (Ref. A-2)

(assumes 70% control for low-NO_x burners)

$Q = (35\ Bbl/hr)(42\ gal/Bbl)(31\ lb/10^3\ gal) +$
$(36{,}000\ scf/hr)(210\ lb/MMscf)$

$Q = 53.1\ lb/hr = 1{,}275\ lb/day = 209\ t/yr$

Carbon Monoxide:

$EF = 5\ lb/10^3\ gal + 17\ lb/MMscf$ (Ref. A-2)

$Q = (35\ Bbl/hr)(42\ gal/Bbl)(5\ lb/10^3\ gal) +$
$(36{,}000\ scf/hr)(17\ lb/MMscf)$

$Q = 8.0\ lb/hr = 191\ lb/day = 31.4\ t/yr$

Particulate:

EF = 3 lb/10^3 gal + 15 lb/MMSCF (Ref. A-2)

(Based on EPA emission factors for residual fuel oil and natural gas combustion)

Q = (35 Bbl/hr)(42 gal/Bbl)(3 lb/10^3 gal) + (36,000 scf/hr)(15 lb/MMscf)

Q = 5.0 lb/hr = 119 lb/day = 19.5 t/yr

I-20. HYDROGEN PLANT

Heat input = 383 MMBtu/hr oil + 53 MMBtu/hr gas

Oil burn rate = (383 MMBtu/hr)/(6.09 MMBtu/Bbl)
= 63 Bbl/hr = 2,640 gal/hr

Gas burn rate = (53 MMBtu/hr)/(806 Btu/scf) = 65,800 scf/hr

Sulfur Dioxide:

EF = 0.284 lb/10^3 gal + 140 lb/MMscf (see calculation # I-19)

Q = (2,640 gal/hr)(0.284 lb/10^3 gal) + (65,800 scf/hr)(140 lb/MMscf)

Q = 10 lb/hr = 239 lb/day = 39 t/yr

Nitrogen Oxides:

EF = 31 lb/10^3 gal + 210 lb/MMscf (see calculation # I-19)

Q = (2,640 gal/hr)(31 lb/10^3 gal) + (65,800 scf/hr)(210 lb/MMscf)

Q = 96 lb/hr = 2,298 lb/day = 377 t/yr

Particulate:

EF = 3 lb/10^3 gal + 15 lb/MMscf (see calculation # I-19)

Q = (2,640 gal/hr)(3 lb/10^3 gal) + (65,800 scf/hr)(15 lb/MMscf)

Q = 8.9 lb/hr = 214 lb/day = 35 t/yr

Carbon Monoxide:

EF = 5 lb/10^3 gal + 17 lb/MMscf (Ref. A-2)

Q = (2,640 gal/hr)(5 lb/10^3 gal) + (65,800 scf/hr)(17 lb/MMscf)

Q = 14 lb/hr = 344 lb/day = 56 t/yr

Hydrocarbons:

EF = 1 lb/10^3 gal + 3 lb/MMscf (Ref. A-2)

Q = (2,640 gal/hr)(1 lb/10^3 gal) + (65,000 scf/hr)(3 lb/MMscf)

Q = 2.8 lb/hr = 68 lb/day = 11 t/yr

I-21. BOILER AND STEAM PLANT

Heat input = 255 MMBtu/hr low Btu gas + 28 MMBtu/hr shale oil

Heat content of low Btu gas = 70 Btu/scf

Heat content of oil = 6.1 MMBtu/Bbl

Volumetric gas burn rate = (255 MMBtu/hr)/(70 Btu/scf)
= 3.64 MMscf/hr

Shale oil burn rate = (28 MMBtu/hr)/(6.1 MMBtu/Bbl) = 4.6 Bbl/hr

Sulfur Dioxide From Fuel Gas Combustion:

Total sulfur content of gas = 175 ppm by wt (based on preliminary data)

Gas density = 0.0759 lb/scf

Sulfur content = (0.0759 lb/scf)(175) = 13.3 lb/MMscf

EF = (13.3 lb-S/MMscf)(64 lb-SO_2/32 lb-S)

EF = 26.6 lb/MMscf as SO_2

Q = (3.64 MMscf/hr)(26.6 lb/MMscf) = 96.8 lb/hr

Q = (96.8 lb/hr)(24 hr/day) = 2324 lb/day

Q = (2324 lb/day)(365 days/yr)(0.9 plant factor)(t/2000 lb)
= 382 t/yr

Sulfur Dioxide From Shale Oil Combustion:

Sulfur content = 20 ppm by wt max

EF = 142 (0.002%) = 0.284 lb/1000 gal (Ref. A-2)

Q = (4.6 Bbl/hr)(42 gal/Bbl)(0.284 lb/1000 gal)

Q = 0.055 lb/hr = 1.3 lb/day = 0.22 t/yr

Total SO_2 From Combustion of Fuel Gas and Shale Oil:

Q = 96.8 lb/hr + 0.055 lb/hr = 96.9 lb/hr

Q = 2325 lb/day = 382 t/yr

Q = (96.9 lb/hr)/(255 + 28 MMBtu/hr) = 0.34 lb/MMBtu

Nitrogen Oxides From Fuel Gas and Shale Oil Combustion:

Ammonia reduced to 10-20 ppmv through the washing of gas in the Superior process.

Thermal NO_x expected to be very low due to the high (66.5% by wt) N_2 content and low flame temperature.

EF = 0.2 lb/MMBtu (design value)

Q = (283 MMBtu/hr)(0.2 lb/MMBtu) = 56.6 lb/hr

Q = 1358 lb/day = 223 t/yr

Hydrocarbons from Fuel Gas Combustion:

EF = 1 lb/10^6 SCF (assumed same as natural gas) (Ref. A-2)

Q = (3.64 MMSCF/hr)(1 lb/MMSCF) = 3.6 lb/hr

Q = 86 lb/day = 14.2 t/yr

Hydrocarbons from Shale Oil Combustion:

EF = 1 lb/1000 gal (assumed same as fuel oil) (Ref. A-2)

Q = (4.6 bbl/hr)(42 gal/bbl)(1 lb/1000 gal) = 0.2 lb/hr

Q = 4.6 lb/day = 0.8 t/yr

Total Hydrocarbons Emissions:

Q = 3.6 + 0.2 = 3.8 lb/hr

Q = 91 lb/day = 15 t/yr

Carbon Monoxide from Fuel Gas Combustion:

EF = 17 lb/10^6 SCF (assumed same as natural gas) (Ref. A-2)

Q = (3.64 MMSCF/hr) (17 lb/MMSCF) = 62 lb/hr

Q = 1485 lb/day = 244 t/yr

Carbon Monoxide from Shale Oil Combustion:

EF = 5 lb/1000 gal (assumed same as fuel oil) (Ref. A-2)

Q = (4.6 bbl/hr)(42 gal/bbl)(5 lb/1000 gal) = 0.97 lb/hr

Q = 23 lb/day = 3.8 t/yr

Total Carbon Monoxide Emissions:

Q = 62 + 1 = 63 lb/hr

Q = 1512 lb/day = 248 t/yr

Particulate from Gas and Shale Oil Combustion:

EF = 0.03 lb/MMBTU (design value)

Q = (283 MMBTU/hr)(0.03 lb/MMBTU) = 8.5 lb/hr

Q = 204 lb/day = 33.5 t/yr

Summary

	lb/day	t/yr	lb/MMBtu
SO_2	2325	382	0.34
NO_x	1358	223	0.20
HC	91	15	-
CO	1512	248	-
Particulate	204	34	0.03

I-22. HYDROTREATER REACTOR FEED FURNACE

Heat input = 31 MMbtu/hr high Btu gas

Heat content = 806 Btu/scf

Volumetric burn rate = (31 MMBtu/hr)/(806 Btu/scf) = 38,460 scf/hr

H_2S content = 0.10 gr/scf (Design value)

Non-H_2S sulfur content = 0.42 gr/scf as H_2S

Total S content = 0.10 (32/34) + 0.42 (32/34) = 0.49 gr/scf as sulfur

Sulfur Dioxide:

Q = (38,460 scf/hr)(0.49 gr/scf)(64/32)(1b/7000 gr)

Q = 5.4 1b/hr

Q = (5.4 1b/hr)(24 hr/day) = 129 1b/day

Q = (129 1b/day)(365 days/yr) (t/2000 1b)(0.9)

Q = 21 t/yr

Q = (5.4 1b/hr)/(31 MMBtu/hr) = 0.17 1b/MMBtu

Nitrogen Dioxide:

EF = 230 1b/10^6 scf (assumed same as natural gas) (Ref. A-2)

Q = (38,460 scf/hr)(230 1b/10^6 scf) = 8.85 1b/hr

Q = (8.85 1b/hr)(24 hr/day) = 212 1b/day

Q = (212 1b/day)(365 days/yr)(t/2000 1b)(0.9)

Q = 35 t/yr

Q = (8.85 1b/hr)/(31 MMBtu/hr) = 0.28 1b/MMBtu

Hydrocarbons:

EF = 3 lb/10^6 scf (assumed same as natural gas) (Ref. A-2)

Q = (38,460 scf/hr)(3 lb/10^6 scf) = 0.12 lb/hr

Q = (0.12 lb/hr)(24 hr/day) = 2.8 lb/day

Q = (2.8 lb/day)(365 days/yr)(t/2000 lb)(0.9)

Q = 0.45 t/yr

Carbon Monoxide:

EF = 17 lb/10^6 scf (assumed same as natural gas) (Ref. A-2)

Q = (38,460 scf/hr)(17 lb/10^6 scf) = 0.65 lb/hr

Q = (0.65 lb/hr)(24 hr/day) = 15.7 lb/day

Q = (15.7 lb/day)(365 days/yr)(t/2000 lb)(0.9)

Q = 2.6 t/yr

Particulate:

EF = 15 lb/10^6 scf (assumed same as natural gas) (Ref. A-2)

Q = (38,460 scf/hr)(15 lb/10^6 scf) = 0.58 lb/hr

Q = (0.58 lb/hr)(24 hr/day) = 14 lb/day

Q = (14 lb/day)(365 days/yr)(t/2000 lb)(0.9)

Q = 2.3 t/yr

Q = (0.58 lb/hr)/(31 MMBtu/hr) = 0.019 lb/MMBtu

Summary:

	lb/day	t/yr	lb/MMBtu
SO_2	129	21	0.17
NO_x	212	35	0.28
HC	2.8	0.45	-
CO	16	2.6	-
Particulate	14	2.3	0.02

I-23. FLARE PILOT

Heat input = 1 MMBtu/hr high Btu gas

Heat content and sulfur content same as Hydrotreater gas (See calculation I-22).

Volumetric burn rate = (1 MMBtu/hr)/(806 Btu/scf) = 1241 scf/hr

Sulfur Dioxide:

Q = (1241 scf/hr)(0.49 gr/scf)(64/32)(lb/7000 gr)

Q = 0.174 lb/hr

Q = (0.174 lb/hr)(24 hr/day) = 4.17 lb/day

Q = (4.2 lb/day)(365 days/yr)(t/2000 lb)(0.9)

Q = 0.68 t/yr

Q = (0.174 lb/hr)/(10^6 Btu/hr) = 0.17 lb/MMBtu

Nitrogen Dioxide:

EF = 230 lb/10^6 scf (assumed same as natural gas) (Ref. A-2)

Q = (1241 scf/hr)(230 lb/10^6 scf) = 0.285 lb/hr

Q = (0.285 lb/hr)(24 hr/day) = 6.85 lb/day

Q = (6.85 lb/day)(365 days/yr)(t/2000 lb)(0.9)

Q = 1.1 t/yr

Q = (0.285 lb/hr)(10^6 Btu/hr) = 0.28 lb/MMBtu

Hydrocarbons:

EF = 3 lb/10^6 (assumed same as natural gas) (Ref. A-2)

Q = (1241 scf/hr)(3 lb/10^6 scf) = 0.004 lb/hr

Q = (0.004 lb/hr)(24 hr/day) = 0.10 lb/day

Q = (0.10 lb/day)(365 days/yr)(t/2000 lb)(0.9)

Q = 0.02 t/yr

Carbon Monoxide:

EF = 17 lb/10^6 scf (assumed same as natural gas) (Ref. A-2)

Q = (1241 scf/hr)(17 lb/10^6 scf) = 0.021 lb/hr

Q = (0.021 lb/hr)(24 hrs/day) = 0.51 lb/day

Q = (0.51 lb/day)(365 days/yr)(t/2000 lb)(0.9)

Q = 0.08 t/yr

Particulate:

EF = 15 lb/10^6 scf (assumed same as natural gas) (Ref. A-2)

Q = (1241 scf/hr)(15 lb/10^6 scf) = 0.019 lb/hr

Q = (0.019 lb/hr)(24 hr/day) = 0.45 lb/day

Q = 0.07 t/yr

Q = (0.019 lb/hr)/(10^6 Btu/hr) = 0.02 lb/MMBtu

Summary:

	lb/day	t/yr	lb/MMBtu
SO_2	4	0.7	0.17
NO_x	7	1.1	0.28
HC	0.1	0.02	-
CO	0.5	0.08	-
Particulate	0.5	0.07	0.02

I-24. GAS TREATMENT PLANT

4 MMBtu/hr high-Btu gas used for incineration. This is equivalent to 4510 scf/hr. Emission factors used to estimate NO_x, CO, HC, and particulate emissions are the same as those used for other high-Btu gas burning equipment. SO_2 emissions are based on 99.9% sulfur recovery.

Sulfur Dioxide:

EF = 4 lb/t (Ref. A-2)

Sulfur production = 29.4 t/day

Q = (4 lb/t)(29.4 t/day) = 118 lb/day

Q = 19 t/yr

(Sulfur dioxide from fuel gas is negligible.)

Nitrogen Dioxide:

EF = 230 lb/MMscf (Ref. A-2)

Q = (4510 scf/hr)(230 lb/MMscf)(24 hr/day)

Q = 25 lb/day = 4.1 t/yr

Particulate:

EF = 15 lb/MMscf (Ref. A-2)

Q = (4510 scf/hr)(15 lb/MMscf)(24 hr/day)

Q = 1.6 lb/day = 0.27 t/yr

Carbon Monoxide:

EF = 17 lb/MMscf (Ref. A-2)

Q = (4510 scf/hr)(17 lb/MMscf)(24 hr/day)

Q = 1.8 lb/day = 0.30 t/yr

Hydrocarbons:

EF = 3 lb/MMscf (Ref. A-2)

Q = (4510 scf/hr)(3 lb/MMscf)(24 hr/day)

Q = 0.32 lb/day = 0.05 t/yr

I-25. UNION CRUDE SHALE OIL STORAGE

Floating roof tank.

Tanks are heated to 100-110F. Tank diameter is 134 ft. Estimated vapor pressure of crude @ 110F = 7 psia

Standing Storage Loss:

From Ref. A-2, vapor loss due to standing storage is given by:

$$L = 9.21 \times 10^{-3} M \left[\frac{P}{12.2 - P}\right]^{0.7} D^{1.5} V^{0.7} K_t K_s K_p K_c$$

where:

L = floating roof standing storage loss (lb/day)

M = molecular weight of vapor in storage tank (lb/lb mole)

P = true vapor pressure at bulk conditions (psia)

D = tank diameter (ft)

V = average wind velocity (mi/hr) = 4 mph for internal or floating roof tanks

K_t = tank type factor

K_s = seal factor

K_p = paint factor

K_c = crude oil factor

$$L = (9.21 \times 10^{-3})(65)\left[\frac{7.0}{12.2-7.0}\right]^{0.7}(134)^{1.5}(4)^{0.7}(0.45)(1)(0.9)(0.84)$$

L = 103 lb/day = 18.8 t/yr

Withdrawal Loss:

Withdrawal loss is given by:

$$L = 22.4\ d\ C/D \qquad \text{(Ref. A-2)}$$

where:

L = floating roof withdrawal loss (lb/1000 gal)

d = density of liquid (lb/gal)

C = tank factor = 0.02 for steel tanks

D = tank diameter (ft)

For Union crude tank:

L = (22.4)(7.1)(0.02)/(134)

L = 0.024 lb/1000 gal

Q = (7,667 Bbl/day)(42 gal/Bbl)(0.024 lb/1000 gal)

Q = 7.7 lb/day = 1.3 t/yr

Total Loss:

Total loss = storage loss + withdrawal loss

Q = 103 + 7.7 = 111 lb/day

Q = 18.8 + 1.3 = 20 t/yr

I-26. SUPERIOR CRUDE SHALE OIL STORAGE

Heated floating roof tank. Use same equations as in calculation I-25 to estimate emissions. Tank diameter is 150 ft.

Standing Storage Loss:

$$L = \left(9.21 \times 10^{-3}\right)(65)\left[\frac{7.0}{12.2 - 7.0}\right]^{0.7}(150)^{1.5}(4)^{0.7}(0.045)(1)(0.9)(0.84)$$

L = 122 lb/day = 22.3 t/yr

Withdrawal Loss:

L = (22.4)(7.1)(0.02)/(150) = 0.021 lb/1000 gal

Q = (8,333 Bbl/day)(42 gal/Bbl)(0.021 lb/1000 gal)

Q = 7.4 lb/day = 1.2 t/yr

Total Loss:

Q = 122 + 7.4 = 129 lb/day

Q = 22.3 + 1.2 = 23.5 t/yr

I-27. SYNTHETIC CRUDE OIL STORAGE

Heated floating roof tank. Use same equations given in calculation I-25. Tank diameter is the same as the Union crude tank (134 ft). Estimated emissions are the same.

Q = 111 lb/day = 20 t/yr

I-28. RECOVERED OIL TANK

Heated floating roof tank. Use same equations given in calculation I-25. Tank diameter is 30 ft.

Standing Storage Loss:

$$L = (0.00921)(65)\left[\frac{7.0}{12.2 - 7.0}\right]^{0.7}(30)^{1.5}(4)^{0.7}(0.045)(1)(0.9)(0.84)$$

L = 11 lb/day = 2.0 t/yr

Withdrawal Loss:

L = (22.4)(7.1)(0.02)/(30) = 0.106 lb/1000 gal

Q = (300 Bbl/day) (42 gal/Bbl)(0.106 lb/1000 gal)

Q = 1.3 lb/day = 0.2 t/yr

Total Loss:

Q = 11 + 1.3 = 12 lb/day

Q = 2.0 + 0.2 = 2.2 t/yr

I-29. DIESEL FUEL TANK

Fixed roof tank. Tank capacity is 17,500 Bbl.

Breathing Loss:

EF = 0.0039 lb/day - 1000 gal (Ref. A-2)

Q = (17,500 Bbl)(42 gal/Bbl)(0.0039 lb/day - 1000 gal)

Q = 2.9 lb/day = 0.53 t/yr

Working Loss:

EF = 0.023 lb/1000 gal (Ref. A-2)

Q = (300 Bbl/day)(42 gal/Bbl)(0.023 lb/1000 gal)

Q = 0.29 lb/day = 0.05 t/yr

Total Loss:

$Q = 2.9 + 0.29 = 3.2$ lb/day

$Q = 0.53 + 0.05 = 0.58$ t/yr

I-30. FUEL OIL TANK

Heated fixed roof tank. Tank capacity = 13,000 Bbl.

Breathing Loss:

EF = 0.00016 lb/1000 gal (Ref. A-2)

Q = (13,000 Bbl)(42 gal/Bbl)(0.00016 lb/1000 gal)

Q = 0.087 lb/day = 0.016 t/yr

Working Loss:

EF = 0.00018 lb/1000 gal (Ref. A-2)

Q = (1,860 Bbl/day)(42 gal/Bbl)(0.00018 lb/1000 gal)

Q = 0.014 lb/day = 0.002 t/yr

Total Loss:

$Q = 0.087 + 0.014 = 0.1$ lb/day

$Q = 0.016 + 0.002 = 0.02$ t/yr

I-31. NAPHTHA TANK

Floating roof tank. Tank diameter = 100 ft. Use equation given in calculation I-25 to estimate emissions.

Standing Storage Loss:

$$L = (0.00921)(80)\left[\frac{1.3}{12.2 - 1.3}\right]^{0.7}(100)^{1.5}(4)^{0.7}(0.045)(1)(0.9)(1)$$

L = 17.8 lb/day = 3.3 t/yr

Withdrawal Loss:

L = (22.4)(6.4)(0.02)/(100) = 0.029 lb/1000 gal

Q = (1,733 Bbl/day)(42 gal/Bbl)(0.029 lb/1000 gal)

Q = 2.1 lb/day = 0.35 t/yr

Total Loss:

Q = 17.8 + 2.1 = 20 lb/day

Q = 3.3 + 0.35 = 3.6 t/yr

I-32. VALVES, FLANGES, PUMP SEALS, ETC.

EF = 50 lb/10^3 Bbl (Ref. A-2)

This is the uncontrolled emission factor derived from EPA's emission factor of petroleum refineries.

Good housekeeping and maintenance are expected to provide 50% control.

Q = (15,925 Bbl/day)(50 lb/1000 Bbl)(1 - 0.5)

Q = 398 lb/day = 65 t/yr

A.2 PHASE I LEAD EMISSIONS

Lead in Raw Shale Dust:

Pb in raw shale = 3 ppm (Ref. A-9)

Q = (96 t/yr dust) (3 ppm) = 0.00029 t/yr

Lead in Processed Shale Dust:

Processed shale can be expected to contain about 96% of the lead in the raw shale (Ref. A-9).

Pb in processed shale = (3 ppm)(0.96)/(0.8 ash) = 3.6 ppm

Q = (82 t/yr dust)(3.6 ppm) = 0.0003 t/yr

Lead in Shale Oil Combustion Flue Gases:

Pb in crude shale oil may range from 0.02% to as much as 4% of the lead in the raw shale (Ref. A-9).

Estimated lead content of upgraded shale oil is 2% of the lead in the raw shale.

Shale oil burn rate = 1910 Bbl/day

$Q = (1910 \text{ Bbl/day})(10^{-7} \text{ t/Bbl}) = 0.00019 \text{ t/day}$

$Q = 0.06 \text{ t/yr}$

Lead from Other Combustion Processes:

Lead emissions from fuel gas combustion and diesel oil combustion should be nil.

Total Lead Emissions:

Raw shale dust = 0.00029 t/yr

Processed shale dust = 0.0003

Shale oil combustion = 0.06

Total = 0.06 t/yr

A.3 PHASE II PARTICULATE, SO_2, NO_x, CO, AND HC EMISSIONS

II-1a. MINING

Particulate:

EF = 0.018 lb/t (Ref. A-1)

Control efficiency = 80% (Wet suppression and settling) (Ref. A-1)

$Q = (93{,}500 \text{ t/day})(0.018 \text{ lb/t})(1-0.8)$

$Q = 337 \text{ lb/day} = 55 \text{ t/yr}$

II-1b. BLASTING

Carbon Monoxide:

EF = 0.022 lb/lb ANFO (Ref. A-1)

Q = (51,000 lb ANFO/day)(0.022 lb/lb ANFO)

Q = 1122 lb/day = 184 t/yr

Nitrogen Oxides:

EF = 0.012 lb/lb ANFO (Ref. A-1)

Q = (51,000 lb ANFO/day)(0.012 lb/lb ANFO)

Q = 612 lb/day = 101 t/yr

II-1c. DIESEL FUEL COMBUSTION

Particulate:

EF = 22 lb/1,000 gal. (Ref. A-2)

Q = (15,900 gal/day)(22 lb/1,000 gal)

Q = 350 lb/day = 57 t/yr

Carbon Monoxide:

EF = 90 lb/1,000 gal (Ref. A-2)

Q = (15,900 gal/day)(90 lb/1,000 gal)

Q = 1431 lb/day = 235 t/yr

Hydrocarbons:

EF = 28 lb/1,000 gal (Ref. A-2)

Q = (15,900 gal/day)(28 lb/1,000 gal)

Q = 445 lb/day = 73 t/yr

Nitrogen Oxides:

EF = 428 lb/1,000 gal (Ref. A-2)

Q = (15,900 gal/day)(428 lb/1,000 gal)

Q = 6805 lb/day = 1118 t/yr

Sulfur Dioxide:

EF = 31 lb/1,000 gal (Ref. A-2)

Q = (15,900 gal/day)(31 lb/1,000 gal)

Q = 493 lb/day = 81 t/yr

II-2a. IN-MINE CRUSHING (PRIMARY)

Particulate:

EF = 0.02 lb/t (Ref. A-3)

Control efficiency = 80% (Wet suppression and settling) (Ref. A-1)

Q = (47,000 t/day)(0.02 lb/t)(1 - 0.8)

Q = 188 lb/day = 31 t/yr

II-2b. IN-MINE CRUSHING (SECONDARY)

Particulate:

Inlet grain loading = 6 gr/scf (Ref. A-4)

Control efficiency = 99.7% (Baghouse) (Ref. A-2)

Outlet grain loading = (6 gr/scf)(1 - 0.997) = 0.018 gr/scf

Q = (15,000 scfm)(0.018 gr/scf)(60 min/hr)(1b/7,000 gr)

Q = 2.3 lb/hr = 55.5 lb/day = 9.1 t/yr

II-3. MINE CONVEYOR SURGE BIN

Particulate:

Inlet grain loading = 4 gr/scf (Ref. A-4)

Control efficiency - 99.7% (Baghouse) (Ref. A-2)

Outlet grain loading = (4 gr/scf)(1 - 0.997) = 0.012 gr/scf

Q = (8,000 scfm)(0.012 gr/scf)(60 min/hr)(lb/7,000 gr)

Q = 0.8 lb/hr = 19.8 lb/day = 3.2 t/yr

II-4. MINE CONVEYOR TRANSFER POINTS

Particulate:

$$EF = \frac{0.0018\ (S/5)(U/5)}{(M/2)^2}$$ (Ref. A-5)

S = 3% silt (estimated)

U = 10 mph

M = 1% moisture (estimated)

$$EF = \frac{0.0018\ (3/5)(10/5)}{(1/2)^2}$$

EF = 0.009 lb/t uncontrolled

Wet suppression control efficiency = 90% (Ref. A-5)

No transfer points on Phase I conveyor. One transfer point on Phase II conveyor.

Q = (66,000 t/day)(0.009 lb/t)(1 - 0.9) = 59.4 lb/day

Q = 9.8 t/yr

II-5. STORAGE SILO FEED

Particulate:

Phase I baghouse = 5,000 cfm

Phase II baghouse = 5,000 cfm

Estimated inlet grain loading = 4 gr/scf

Baghouse control efficiency = 99.7%

Outlet grain loading = (4 gr/scf)(0.003) = 0.012 gr/scf

Q, Phase I baghouse = 12.3 lb/day = 2 t/yr (see previous Phase I calculations)

Q, Phase II baghouse = 12.3 lb/day = 2 t/yr

Total = 12.3 + 12.3 = 24.6 lb/day = 4.0 t/yr

II-6. SURFACE CRUSHING AND SCREENING

Particulate:

Phase I baghouse = 15,000 cfm

Phase II baghouse = 15,000 cfm

Estimated inlet grain loading = 7 gr/scf

Bahouse control efficiency = 99.7%

Outlet grain loading = 0.021 gr/scf

Q, Phase I baghouse = 65 lb/day (see Phase I calculations)

Q, Phase II baghouse = 65 lb/day

Total = 65 + 65 = 130 lb/day = 21.4 t/yr

II-7. FINES CONVEYOR FEED

Particulate:

EF = 0.04 lb/t (see Phase I caluculations)

Wet suppression for control = 90%

Phases I & II conveyor:

Q = (9400 t/day)(0.04 lb/t)(0.1) = 38 lb/day

Q = 6.2 t/yr

II-8. FINES CONVEYOR TRANSFER POINTS

Particulate:

EF = 0.04 lb/t (see calculation I-6)

Wet suppression for control = 90%

Phases I & II Sections:

Q = (9400 t/day)(0.04 lb/t)(0.1) = 37.6 lb/day each

Four (4) transfer points.

Q (total) = (38 lb/day)(4) = 152 lb/day = 25 t/yr

II-9. TOSCO RETORT FEED SILOS

Particulate:

Inlet grain loading = 3 gr/scf

Baghouse control efficiency = 99.7%

Outlet grain loading = (3 gr/scf)(0.003) = 0.009 gr/scf

Q = (5000 cfm)(0.009 gr/scf) = 45 gr/min

Q = (45 gr/min)(60 min/hr)(lb/7000 gr) = 0.4 lb/hr

Q = 9.3 lb/day = 1.5 t/yr

II-10. UNION CONVEYOR FEED

Particulate:

EF = 0.006 lb/t (see calculation I-9)

Wet suppression for control = 90%

Phase I conveyor:

Q = (11,600 t/day)(0.006 lb/t)(0.1) = 7 lb/day

Q = 1.1 t/yr

Phase II conveyor:

Q = (34,800 t/day)(0.006 lb/t)(0.1) = 21 lb/day

Q = 3.4 t/yr

Summary:

	lb/day	t/yr
Phase I conveyor	7	1.1
Phase II conveyor	21	3.4
	28	4.5

II-11. UNION RETORT FEED SILOS

Particulate:

Four (4) 1,000 cfm baghouses.

Q = 2 lb/day each (see calculation I-10)

Q (total) = (2 lb/day)(4) = 8 lb/day = 1.3 t/yr

II-12. SUPERIOR CONVEYOR FEED

Particulate:

EF = 0.006 lb/t uncontrolled (see calculation I-11)

Wet suppression for control = 90%

For Phases I and II conveyors:

Throughput = 38,000 t/day

Q = (38,000 t/day)(0.006 lb/t)(0.1) = 23 lb/day = 3.7 t/yr

II-13. SUPERIOR RETORT FEED SILOS AND BINS

Particulate:

Two baghouses on each of the two Superior retorts. One @ 5,000 cfm and one @ 3,200 cfm. Total cfm each retort is 8200 cfm.

Q = 17 lb/day = 2.8 t/yr each (see calculation I-12)

Q = 34 lb/day = 5.6 t/yr total

II-14. UNION DISCHARGE TO PROCESSED SHALE CONVEYOR

Particulate:

EF = 0.0001 lb/t (see calculation I-13)

Q = (Phase I retort) = (9875 t/day)(0.0001 lb/t) = 1 lb/day

Q = (Phase II retorts) = (1 lb/day each)(3 retorts) = 3 lb/day

Q (total) = 4 lb/day = 0.7 t/yr

II-15. TOSCO DISCHARGE TO PROCESSED SHALE CONVEYOR

Particulate:

EF = 0.0001 lb/t (same as Union)

Q (Phase II retort) = (8235 t/day)(0.0001 lb/t) = 1 lb/day = 0.1 t/yr

II-16,17. SUPERIOR DISCHARGE TO PROCESSED SHALE CONVEYOR

Particulate:

EF = 0.0001 lb/t (same as Union)

Q (Phase I retort) = (11,000 t/day)(0.0001 lb/t) = 1 lb/day

Q (Phase II retort) = (21,000 t/day)(0.0001 lb/t) = 2 lb/day

Q (total) = 3 lb/day = 0.5 t/yr

II-18. PROCESSED SHALE CONVEYOR TRANSFER POINTS

Particulate:

$$EF = \frac{0.0018\ (S/5)(U/5)}{(M/2)^2}$$ (Ref. A-5)

S = 20% silt (estimated)

U = 10 mph

M = 15% moisture (estimated)

$$EF = \frac{0.0018(20/5)(10/5)}{(15/2)^2} = 0.0003 \text{ lb/t}$$

Processed shale throughput = 79,400 t/day

Q = (79,400 t/day)(0.0003 lb/t) = 23.8 lb/day each

Q = 3.9 t/yr each

Three transfer points.

Q (total) = 71 lb/day = 12 t/yr

II-19. PROCESSED SHALE DISPOSAL

Particulate:

a. Load-in by stacker conveyor:

$$EF = \frac{0.0018(S/5)(U/5)(H/10)}{(M/2)^2}$$ (Ref. A-5)

S = 20% silt (estimated)

U = 10 mph

H = 10 ft drop

M = 15% moisture (estimated)

$$EF = \frac{0.0018\ (20/5)(10/5)(10/10)}{(15/2)^2} = 0.0003 \text{ lb/t}$$

Q = (79,400 t/day)(0.0003 lb/t) = 23.8 lb/day

Q = 3.9 t/yr

b. Grooming and compaction:

EF = 16 lb/scraper-hour (uncontrolled) (Ref. A-6)

Q = (60 scraper-hours/day)(16 lb/scraper-hour)
= 960 lb/day

This will be the worst daily rate. Watering will be used to control dust when practical. On an annual basis, 50% control is expected to be achieved.

Q = 79 t/yr

c. Wind erosion:

EF = 8570 lb/acre-year (see calculation I-18d)

Maximum of 30 acres exposed.

Control efficiency = 85% for compaction and chemical dust suppressants.

Q = (30 acres)(8570 lb/acre-yr)(0.15)(t/2000 lb)

Q = 19 t/yr = 106 lb/day

d. Summary:

	lb/day	t/yr
Load-in	24	4
Grooming and compaction	960	79
Wind erosion	106	19
	1090	102

II-20. COARSE SHALE STOCKPILE

Particulate:

a. Load-in

EF = 0.009 lb/t (see calculation I-16a)

Control efficiency = 75% (Lowering well)

Q = (2,700 t/day)(0.009 lb/t)(0.25) = 6.1 lb/day

Q = 1.0 t/yr

b. Grooming

EF = 0.02 lb/t (see calculation I-16b)

Q = (2,700 t/day)(0.02 lb/t) = 54 lb/day

On an annual basis, 50% control is expected to be achieved by watering.

Q = (54 lb/day)(0.5)(365 days/yr)(t/2000 lb)(0.9)

Q = 4.4 t/yr

c. Wind erosion

EF = 0.32 lb/t-yr (see calculation I-16c)

A total of 2 million tons will be stored in 2 piles. One of the stockpiles containing 1.5 million tons will be dead storage and will be sealed to prevent wind erosion and to preserve the quality of the raw shale. In the other pile which will contain 0.5 million tons, 65% will be dead storage and will be sealed. Total dead storage = 1.5 + (0.65)(0.5) = 1.83 million tons. Ninety-five percent control of fugitive dust is expected to be achieved.

Dead storage wind erosion:

Q = (1,830,000 t)(0.32 lb/t-yr)(0.05)(yr/365 days)

Q = 80 lb/day = 14.6 t/yr

The remaining 35% of the half-million ton pile will be live storage.

Live storage wind erosion:

Q = (500,000 t)(0.35)(0.32 lb/t-yr)(yr/365 days)

Q = 153 lb/day

On an annual basis, 50% control of fugitive dust from live storage will be achieved by watering.

Q = (153 lb/day)(0.5)(365 days/yr)(t/2000 lb)

Q = 14 t/yr

Total for wind erosion:

	lb/day	t/yr
Dead	80	15
Live	153	14
	233	29

d. Under-the-pile reclaim

Reclaim will be non-routine. Any associated emissions are expected to be approximately offset by the discontinued operation of routine equipment.

e. Summary

	lb/day	t/yr
Load-in	6	1
Grooming	54	4
Wind erosion	277	29
Reclaim	-	-
	337	34

II-21. UNION RECYCLE GAS HEATERS

Heat input = 685 MMBtu oil + 275 MMBtu gas

Heat content oil = 6.09 MMBtu/Bbl

Heat content gas = 871 Btu/scf

Burn rate = (685 MMBtu/hr)/(6.09 MMBtu/Bbl)

+ (275 MMBtu/hr)/(871 Btu/scf)

= 112 Bbl/hr + 316,000 scf/hr

Sulfur Dioxide:

EF = 0.284 lb/10^3 gal + 140 lb/MMscf (see calculation I-19)

Q = (112 Bbl/hr)(42 gal/Bbl)(0.284 lb/10^3 gal)
+ (316,000 scf/hr)(140 lb/MMscf)

Q = 46 lb/hr = 1094 lb/day = 180 t/yr

Particulate:

EF = 3 lb/10^3 gal + 15 lb/MMscf (see calculation I-19)

Q = (112 Bbl/hr)(42 gal/Bbl)(3 lb/10^3 gal)
+ (316,000 scf/hr)(15 lb/MMscf)

Q = 19 lb/hr = 452 lb/day = 74.3 t/yr

Nitrogen Oxides:

EF = 31 lb/10^3 gal + 210 lb/MMscf (see calculation I-19)

Q = (112 Bbl/hr)(42 gal/Bbl)(31 lb/10^3 gal)
+ (316,000 scf/hr)(210 lb/MMscf)

Q = 212 lb/hr = 5,092 lb/day = 836 t/yr

Carbon Monoxide:

EF = 5 lb/10^3 gal + 17 lb/MMscf (see calculation I-19)

Q = (112 Bbl/hr)(42 gal/Bbl)(5 lb/10^3 gal)
+ (316,000 scf/hr)(17 lb/MMscf)

Q = 29 lb/hr = 693 lb/day = 114 t/yr

Hydrocarbons:

EF = 1 lb/10^3 gal + 3 lb/MMscf (see calculation I-19)

Q = (112 Bbl/hr)(42 gal/Bbl)(1 lb/10^3 gal)
+ (316,000 scf/hr)(3 lb/MMscf)

Q = 5.6 lb/hr = 136 lb/day = 22.3 t/yr

II-22. TOSCO BALL HEATERS AND LIFT PIPES

Heat input = 241 MMBtu/hr high-Btu gas

Heat content oil = 6.09 MMBtu/Bbl

Heat content gas = 871 Btu/scf

Burn rate = (241 MMBtu/hr)/(871 Btu/scf)

= 276,700 scf/hr

Sulfur Dioxide:

EF = 140 lb/MMscf (see calculation I-19)

Q = 276,700 scf/hr)(140 lb/MMscf)

Q = 38.7 lb/hr = 930 lb/day = 153 t/yr

Colony data suggest 95% of the SO_2 may be absorbed by the raw shale. No credit is taken for this, but SO_2 emissions may actually be much lower than estimated.

Nitrogen Oxides:

EF = 210 lb/MMscf (see calculation I-19)

Q = (276,700 scf/hr)(210 lb/MMscf)

Q = 58.0 lb/hr = 1391 lb/day = 228 t/yr

Carbon Monoxide:

EF = 17 lb/MMscf (see calculation I-19)

Q = (276,700 scf/hr)(17 lb/MMscf)

Q = 4.7 lb/hr = 113 lb/day = 18.5 t/yr

Hydrocarbons:

EF = 0.73 lb/ton-shale feed (Ref. A-7)

Incinerator provides 85% control (Ref. A-7)

Q = (9,350 TPSD)(0.73 lb/t)(1-0.85)

Q = 1024 lb/day = 168 t/yr

Particulate:

Particulate emissions are due primarily to particulate taken up from the raw shale feed by the ball heater flue gas used for preheating. Cyclones at 93.8% control efficiency (Ref. A-2) and venturi scrubbers at 99.5% control efficiency (Ref. A-2) will be employed in series.

Inlet grain loading = 64.5 gr/scf (based on Colony test data, Ref. A-8).

Outlet grain loading = (64.5 gr/scf)(1-0.938)(1-0.995)
= 0.02 gr/scf

Exhaust volume from scrubber = 131,000 scfm

Q = (131,000 scfm)(0.02 gr/scf)(lb/7000 gr)(60 min/hr)

Q = 22.5 lb/hr = 539 lb/day = 88.5 t/yr

II-23a. TOSCO ELUTRIATORS

Particulate:

If feasible, a portion of the boiler plant flue gases may be diverted to the TOSCO elutriators to preheat the ceramic heat transfer balls. Only particulate emissions resulting from this operation are estimated below. All boiler plant flue gas emissions are included with the boiler plants.

EF = 1% raw shale feed, uncontrolled (estimated)

Cyclone control efficiency = 93.8% (Ref. A-2)

Venturi scrubber control efficiency = 99.5% (Ref. A-2)

Q = (9,350 TPSD)(1%)(1-0.938)(1-0.995)(2000 lb/t)

Q = 58 lb/day = 9.5 t/yr

II-23b. TOSCO PROCESSED SHALE MOISTURIZERS

Particulate:

Venturi scrubber @ 99.5% control efficiency.

Inlet grain loading = 4 gr/scf (based on rock cooling operations, Ref. A-4).

Outlet grain loading = (4 gr/scf)(1-0.995) = 0.02 gr/scf

Exhaust volume = 25,000 scfm

Q = (25,000 scfm)(0.02 gr/scf)(lb/7000 gr)(60 min/hr)

Q = 4.3 lb/hr = 103 lb/day = 17 t/yr

II-24. HYDROGEN PLANTS

3 reformer furnaces (oil and gas fired)

Heat input:

	Oil	Gas	
Phase I Plant	383	53	MMBtu/hr
Phase II Plant	759	43	
Total	1,142	96	

Heat content of oil = 6.09 MMBtu/Bbl

Heat content of gas = 871 Btu/scf

Burn rates:

	Bbl/hr	scf/hr
Phase I Plant	63	60,850
Phase II Plant	125	49,370

Sulfur Dioxide:

EF = 0.284 lb/10^3 gal + 140 lb/MMscf (see calculation I-19)

Phase I Plant:

Q = (63 Bbl/hr)(42 gal/Bbl)(0.284 lb/10^3 gal)
+ (60,850 scf/hr)(140 lb/MMscf)

Q = 9.3 lb/hr = 222 lb/day = 36.5 t/yr

Phase II Plant:

Q = (125 Bbl/hr)(42 gal/Bbl)(0.284 lb/10^3 gal)
+ (49,370 scf/hr)(140 lb/MMscf)

Q = 8.4 lb/hr = 202 lb/day = 33.1 t/yr

Particulate:

EF = 3 lb/10^3 gal + 15 lb/MMscf (see calculation I-19)

Phase I Plant:

Q = (63 Bbl/hr)(42 gal/Bbl)(3 lb/10^3 gal)
+ (60,850 scf/hr)(15 lb/MMscf)

Q = 8.8 lb/hr = 212 lb/day = 34.9 t/yr

Phase II Plant:

Q = (125 Bbl/hr)(42 gal/Bbl)(3 lb/10^3 gal)
+ (49,370 scf/hr)(15 lb/MMscf)

Q = 16.5 lb/hr = 396 lb/day = 65.0 t/yr

Nitrogen Oxides:

EF = 31 lb/10^3 gal + 210 lb/MMscf (see calculation I-19)

Phase I Plant:

Q = (63 Bbl/hr)(42 gal Bbl)(31 lb/10^3 gal)
+ (60,850 scf/hr)(210 lb/MMscf)

Q = 94.8 lb/hr = 2275 lb/day = 374 t/yr

Phase II Plant:

Q = (125 Bbl/hr)(42 gal/Bbl)(31 lb/10^3 gal)
+ (49,370 scf/hr)(210 lb/MMscf)

Q = 173 lb/hr = 4155 lb/day = 682 t/yr

Carbon Monoxide:

EF = 5 lb/10^3 gal + 17 lb/MMscf (see calculation I-19)

Phase I Plant:

Q = (63 Bbl/hr)(42 gal/Bbl)(5 lb/10^3 gal)
+ (60,850 scf/hr)(17 lb/MMscf)

Q = 14.3 lb/hr = 342 lb/day = 56.2 t/yr

Phase II Plant:

$Q = (125\ Bbl/hr)(42\ gal/Bbl)(5\ lb/10^3\ gal)$
$+ (49{,}370\ scf/hr)(17\ lb/MMscf)$

$Q = 27.1\ lb/hr = 650\ lb/day = 107\ t/yr$

Hydrocarbons:

$EF = 1\ lb/10^3\ gal + 3\ lb/MMscf$ (see calculation I-19)

Phase I Plant:

$Q = (63\ Bbl/hr)(42\ gal/Bbl)(1\ lb/10^3\ gal)$
$+ (60{,}850\ scf/hr)(3\ lb/MMscf)$

$Q = 2.8\ lb/hr = 67.9\ lb/day = 11.2\ t/yr$

Phase II Plant:

$Q = (125\ Bbl/hr)(42\ gal/Bbl)(1\ lb/10^3\ gal)$
$+ (49{,}370\ scf/hr)(3\ lb/MMscf)$

$Q = 5.4\ lb/hr = 130\ lb/day = 21.3\ t/yr$

II-25a. PHASE I BOILER PLANT

See Phase I calculations for emissions from Phase I Boiler Plant (calculation I-21). Emissions are the same in Phase II, except SO_2 emissions are reduced by 80% by FGD.

II-25b. PHASE II BOILER PLANT

Heat input = 485 MMBtu/hr low-Btu gas +
54 MMBtu/hr upgraded shale oil

Heat content of gas = 70 Btu/scf

Heat content of oil = 6.1 MMBtu/Bbl

Gas burn rate = (485 MMBtu/hr)/(70 Btu/scf)
= 6.93 MMscf/hr

Oil burn rate = (54 MMBtu/hr)/(6.09 MMBtu/Bbl)
= 8.9 Bbl/hr

Sulfur Dioxide:

EF = 26.6 lb/MMscf + 0.284 lb/10^3 gal (see calculation I-21)

Q = (6.93 MMscf/hr)(26.6 lb/MMscf) +
(8.9 Bbl/hr)(42 gal/Bbl)(0.284 lb/1000 gal)

Q = 184.4 lb/hr = 4427 lb/day = 727 t/yr

FGD to provide 80% reduction.

Q = (4427 lb/day)(1-0.8) = 885 lb/day

Q = 145 t/yr

Nitrogen Oxides:

EF = 0.2 lb/MMBtu (Design value)

Q = (539 MMBtu/hr)(0.2 lb/MMBtu)

Q = 108 lb/hr = 2587 lb/day = 425 t/yr

Particulate:

EF = 0.03 lb/MMBtu (Design value)

Q = (539 MMBtu/hr)(0.03 lb/MMBtu)

Q = 16 lb/hr = 388 lb/day = 64 t/yr

Carbon Monoxide:

EF = 17 lb/MMscf + 5 lb/10^3 gal (Ref. A-2)

Q = (6.93 MMscf/hr)(17 lb/MMscf) +
(8.9 Bbl/hr)(42 gal/Bbl)(5 lb/10^3 gal)

Q = 120 lb/hr = 2873 lb/day = 472 t/yr

Hydrocarbons:

EF = 1 lb/MMscf + 1 lb/10^3 gal (Ref. A-2)

Q = (6.93 MMscf/hr)(1 lb/MMscf) +
(8.9 Bbl/hr)(42 gal/Bbl)(1 lb/10^3 gal)

Q = 7.3 lb/hr = 175 lb/day = 29 t/yr

II-26a. PHASE I HYDROTREATER PLANT

Heat input = 31 MMbtu/hr high-Btu gas

Heat content = 871 Btu/scf

Volumetric burn rate = (31 MMBtu/hr)/(871 Btu/scf) = 35,590 scf/hr

H_2S content = 0.10 gr/scf (Design value)

Non-H_2S sulfur content = 0.42 gr/scf as H_2S

Total S content = 0.10 (32/34) + 0.42 (32/34) = 0.49 gr/scf as sulfur

Sulfur Dioxide

Q = (35,590 scf/hr)(0.49 gr/scf)(64/32)(lb/7000 gr) = 5.0 lb/hr

Q = (5.0 lb/hr)(24 hr/day) = 120 lb/day

Q = (120 lb/day)(365 days/yr)(t/2000 lb)(0.9) = 19.7 t/yr

Q = (5.0 lb/hr)/(31 MMBtu/hr) = 0.16 lb/MMBtu

Nitrogen Dioxide:

EF = 230 lb/10^6 scf (assumed same as natural gas) (Ref. A-2)

Q = (35,590 scf/hr)(230 lb/10^6 scf) = 8.2 lb/hr

Q = (8.2 lb/hr)(24 hr/day) = 196 lb/day

Q = (196 lb/day)(365 days/yr)(t/2000 lb)(0.9) = 32 t/yr

Q = (8.2 lb/hr)/(31 MMBtu/hr) = 0.26 lb/MMBtu

Hydrocarbons:

EF = 3 lb/10^6 scf (assumed same as natural gas) (Ref. A-2)

Q = (35,590 scf/hr)(3 lb/10^6 scf) = 0.11 lb/hr

Q = (0.11 lb/hr)(24 hr/day) = 2.6 lb/day

Q = (2.6 lb/day)(365 days/yr)(t/2000 lb)(0.9) = 0.42 t/yr

Carbon Monoxide:

EF = 17 lb/10^6 scf (assumed same as natural gas) (Ref. A-2)

Q = (35,590 scf/hr)(17 lb/10^6 scf) = 0.61 lb/hr

$Q = (0.61\ lb/hr)(24\ hr/day) = 14.5\ lb/day$

$Q = (14.5\ lb/day)(365\ days/yr)(t/2000\ lb)(0.9) = 2.4\ t/yr$

Particulate:

$EF = 15\ lb/10^6\ scf$ (assumed same as natural gas) (Ref. A-2)

$Q = (35{,}590\ scf/hr)(15\ lb/10^6\ scf) = 0.53\ lb/hr$

$Q = (0.53\ lb/hr)(24\ hr/day) = 12.8\ lb/day$

$Q = (12.8\ lb/day)(365\ days/yr)(t/2000\ lb)(0.9) = 2.1\ t/yr$

$Q = (0.53\ lb/hr)/(31\ MMBtu/hr) = 0.017\ lb/MMBtu$

II-26b. PHASE II HYDROTREATER PLANT

Heat input = 56 MMBtu/hr high-Btu gas

Heat content = 871 Btu/scf

Volumetric burn rate = (56 MMBtu/hr)/(871 Btu/scf) = 64,300 scf/hr

H_2S content = 0.10 gr/scf (Design value)

Non-H_2S sulfur content = 0.42 gr/scf as H_2S

Total S content = 0.10 (32/34) + 0.42 (32/34) = 0.49 gr/scf as sulfur

Sulfur Dioxide:

$Q = (64{,}300\ scf/hr)(0.49\ gr/scf)(64/32)(lb/7000\ gr)$

$Q = 9.0\ lb/hr$

$Q = (9.0\ lb/hr)(24\ hr/day) = 216\ lb/day$

$Q = 216\ lb/day)(365\ days/yr)(t/2000\ lb)(0.9)$

$Q = 36\ t/yr$

$Q = (9.0\ lb/hr)/(56\ MMBtu/hr) = 0.16\ lb/MMBtu$

Nitrogen Dioxide:

$EF = 230\ lb/10^6\ scf$ (assumed same as natural gas) (Ref. A-2)

$Q = (64{,}300\ scf/hr)(230\ lb/10^6\ scf) = 14.8\ lb/hr$

$Q = (14.8\ lb/hr)(24\ hr/day) = 355\ lb/day$

$Q = (355\ lb/day)(365\ days/yr)(t/2000\ lb)(0.9)$

$Q = 58\ t/yr$

$Q = (14.8\ lb/hr)/(56\ MMBtu/hr) = 0.26\ lb/MMBtu$

Hydrocarbons:

EF = 3 lb/10^6 scf (assumed same as natural gas) (Ref. A-2)

Q = (64,300 scf/hr)(3 lb/10^6 scf) = 0.19 lb/hr

Q = (0.19 lb/hr)(24 hr/day) = 4.6 lb/day

Q = (4.6 lb/day)(365 days/yr)(t/2000 lb)(0.9)

Q = 0.76 t/yr

Carbon Monoxide:

EF = 17 lb/10^6 scf (assumed same as natural gas) (Ref. A-2)

Q = (64,300 scf/hr)(17 lb/10^6 scf) = 1.1 lb/hr

Q = (1.1 lb/hr)(24 hr/day) = 26.2 lb/day

Q = (26.2 lb/day)(365 days/yr)(t/2000 lb)(0.9)

Q = 4.3 t/yr

Particulate:

EF = 15 lb/10^6 scf (assumed same as natural gas) (Ref. A-2)

Q = (64,300 scf/hr)(15 lb/10^6 scf) = 0.96 lb/hr

Q = (0.96 lb/hr)(24 hr/day) = 23 lb/day

Q = (23 lb/day)(365 days/yr)(t/2000 lb)(0.9)

Q = 3.8 t/yr

Q = (0.967 lb/hr)/(56 MMBtu/hr) = 0.017 lb/MMBtu

II-27. FLARE PILOTS

Heat input = 1 MMBtu/hr high-Btu gas each.

Two flare pilots.

Heat content and sulfur content same as Hydrotreater gas.

Volumetric burn rate = (2 MMBtu/hr)/(871 Btu/scf) = 2300 scf/hr

Sulfur Dioxide:

Q = (2300 scf/hr)(0.49 gr/scf)(64/32)(lb/7000 gr) = 0.32 lb/hr

$Q = (0.32\ lb/hr)(24\ hr/day) = 7.7\ lb/day$

$Q = (7.7\ lb/day)(365\ days/yr)(t/2000\ lb)(0.9) = 1.3\ t/yr$

Nitrogen Dioxide:

$EF = 230\ lb/10^6\ scf$ (assumed same as natural gas) (Ref. A-2)

$Q = (2300\ scf/hr)(230\ lb/10^6\ scf) = 0.53\ lb/hr$

$Q = (0.53\ lb/hr)(24\ hr/day) = 12.7\ lb/day$

$Q = (12.7\ lb/day)(365\ days/yr)(t/2000\ lb)(0.9) = 2.1\ t/yr$

Hydrocarbons:

$EF = 3\ lb/10^6$ (assumed same as natural gas) (Ref. A-2)

$Q = (2300\ scf/hr)(3\ lb/10^6\ scf) = 0.007\ lb/hr$

$Q = (0.007\ lb/hr)(24\ hr/day) = 0.16\ lb/day$

$Q = (0.16\ lb/day)(365\ days/yr)(t/2000\ lb)(0.9) = 0.03\ t/yr$

Carbon Monoxide:

$EF = 17\ lb/10^6\ scf$ (assumed same as natural gas) (Ref. A-2)

$Q = (2300\ scf/hr)(17\ lb/10^6\ scf) = 0.04\ lb/hr$

$Q = (0.04\ lb/hr)(24\ hrs/day) = 0.94\ lb/day$

$Q = (0.94\ lb/day)(365\ days/yr)(t/2000\ lb)(0.9) = 0.15\ t/yr$

Particulate:

$EF = 15\ lb/10^6\ scf$ (assumed same as natural gas) (Ref. A-2)

$Q = (2300\ scf/hr)(15\ lb/10^6\ scf) = 0.034\ lb/hr$

$Q = (0.034\ lb/hr)(24\ hr/day) = 0.83\ lb/day = 0.14\ t/yr$

II-28a. PHASE I GAS TREATMENT PLANT

4 MMBtu/hr high-Btu gas used for incineration. This is equivalent to 4590 scf/hr. Emission factors used to estimate NO_x, CO, HC, and particulate emissions are the same as those used for other high-Btu gas burning equipment. SO_2 emissions are based on 99.9% sulfur recovery.

Sulfur Dioxide:

EF = 4 lb/t (Ref. A-2)

Sulfur production = 29.4 t/day

Q = (4 lb/t)(29.4 t/day) = 118 lb/day

Q = 19 t/yr

(Sulfur dioxide from fuel gas is negligible.)

Nitrogen Dioxide:

EF = 230 lb/MMscf (Ref. A-2)

Q = (4590 scf/hr)(230 lb/MMscf)(24 hr/day)

Q = 25 lb/day = 4.2 t/yr

Particulate:

EF = 15 lb/MMscf (Ref. A-2)

Q = (4590 scf/hr)(15 lb/MMscf)(24 hr/day)

Q = 1.6 lb/day = 0.27 t/yr

Carbon Monoxide:

EF = 17 lb/MMscf (Ref. A-2)

Q = (4590 scf/hr)(17 lb/MMscf)(24 hr/day)

Q = 1.9 lb/day = 0.31 t/yr

Hydrocarbons:

EF = 3 lb/MMscf (Ref. A-2)

Q = (4590 scf/hr)(3 lb/MMscf)(24 hr/day)

Q = 0.33 lb/day = 0.05 t/yr

II-28b. PHASE II GAS TREATMENT PLANT

13 MMBtu/hr high-Btu gas used for incineration. This is equivalent to 14,900 scf/hr. Emission factors used to estimate NO_x, CO, HC,

and particulate emissions are the same as those used for other high-Btu gas burning equipment. SO_2 emissions are based on 99.9% sulfur recovery.

Sulfur Dioxide:

EF = 4.6 lb/t (Ref. A-2)

Sulfur production = 95.8 t/day

Q = (4.6 lb/t)(95.8 t/day) = 441 lb/day

Q = 72 t/yr

(Sulfur dioxide from fuel gas is negligible.)

Nitrogen Dioxide:

EF = 230 lb/MMscf (Ref. A-2)

Q = (14,900 scf/hr)(230 lb/MMscf)(24 hr/day)

Q = 82 lb/day = 14 t/yr

Particulate:

EF = 15 lb/MMscf (Ref. A-2)

Q = (14,900 scf/hr)(15 lb/MMscf)(24 hr/day)

Q = 5.4 lb/day = 0.88 t/yr

Carbon Monoxide:

EF = 3 lb/MMscf (Ref. A-2)

Q = (14,900 scf/hr)(17 lb/MMscf)(24 hr/day)

Q = 6.1 lb/day = 1.0 t/yr

Hydrocarbons:

EF = 3 lb/MMscf (Ref. A-2)

Q = (14,900 scf/hr)(3 lb/MMscf)(24 hr/day)

Q = 1.1 lb/day = 0.18 t/yr

II-29. CRUDE SHALE OIL STORAGE

Standing Storage Loss:

See caluculations I-25 and I-26 for emissions from tanks installed during Phase I. During Phase II, two tanks of 180 feet diameter each will be constructed. Using equations given previously in calculation I-25 (except that the diameter correction term is modified, as suggested by AP-42, to allow for the relatively large tank diameter):

$$L = (9.21 \times 10^{-3})(65)\left[\frac{7}{12.2 - 7}\right]^{0.7}(180)(150)^{0.5}(4)^{0.7}(0.045)(1)(0.9)(0.84)$$

L = 146 lb/day per tank

L = (146 lb/day) (2 tanks) = 292 lb/day = 53.2 t/yr

Working Loss:

L = (22.4)(7.1)(0.02)/180 = 0.018 lb/1,000 gal

Q = (28,000 Bbl/day)(42 gal/Bbl)(0.018 lb/1,000 gal)

Q = 21.2 lb/day = 3.5 t/yr

Total

	lb/day (t/yr)		
	Storage	Working	Total
Phase I Union Tank	103(19)	7.7(1.3)	111(20)
Phase II Superior Tank	122(22)	(7.4)(1.2)	129(23)
Phase III Combined Tanks	292(53)	21 (3.5)	313(57)
			553(100)

II-30. SNYTHETIC CRUDE SHALE OIL STORAGE

See calculation I-27 for emissions from the Phase I tank. During Phase II, two 180-foot diamter tanks will be added.

Standing Storage Loss:

Tanks are same diameter as Phase II crude tanks. Emissions are estimated to be the same as in calculation II-29.

L = 292 lb/day = 53.2 t/yr

Working Loss:

L = 0.018 lb/1,000 gal (see calculation II-29)

Q = (27,000 Bbl/day)(0.018 lb/1,000 gal)(42 gal/Bbl)

Q = 20.4 lb/day = 3.4 t/yr

Total:

	lb/day (t/yr)		
	Storage	Withdrawal	Total
Phase I Tank	103 (19)	7.7 (1.3)	111 (20)
Phase II Tanks	292 (53)	20 (3.4)	312 (56)
			423 (76)

II-31. RECOVERED OIL (SLOP) TANKS

See calculation I-28 for emissions from Phase I tank. In Phase II, an additional tank will be installed (43 feet in diameter).

Standing Storage Loss:

$$L = (9.21 \times 10^{-3})(65)\left[\frac{7}{12.2 - 7}\right]^{0.7} (43)^{1.5} (4)^{0.7} (0.045)(1)(0.9)(0.84)$$

L = 18.6 lb/day = 3.4 t/yr

Working Loss:

L = (22.4)(7.1)(0.02)/43 = 0.074 lb/1000 gal.

Q = (667 Bbl/day)(42 gal/Bbl)(0.074 lb/1000 gal)

Q = 2.1 lb/day = 0.34 t/yr

Total Loss:

	lb/day (t/yr)		
	Storage	Working	Total
Phase I Tank	11 (2.0)	1.3 (0.22)	12 (2.2)
Phase II Tank	19 (3.4)	2.1 (0.34)	21 (3.7)
			33 (5.9)

II-32. DIESEL FUEL TANKS

See calculation I-29 for emissions from Phase I tank. In Phase II, another fixed roof tank of 22,500 Bbl capacity will be added.

Standing Storage Loss:

EF = 0.0039 lb/day-1000 gal (Ref. A-2)

Q = (22,500 Bbl)(0.0039 lb/day/1000 gal)(42 gal/Bbl)

Q = 3.7 lb/day = 0.67 t/yr

Working Loss:

EF = 0.023 lb/1000 gal (Ref. A-2)

Q = (375 Bbl/day)(42 gal/Bbl)(0.023 lb/1000 gal)

Q = 0.36 lb/day = 0.06 t/yr

Total Loss:

	lb/day (t/yr)		
	Storage	Working	Total
Phase I Tank	2.9 (0.53)	0.29 (0.05)	3.2 (0.58)
Phase II Tank	3.7 (0.67)	0.36 (0.06)	4.1 (0.73)
			7.3 (1.31)

II-33. FUEL OIL TANKS

See calculation I-30 for emissions from Phase I tank. In Phase II, another fixed roof fuel oil tank of 55,000 Bbl capacity will be added.

Standing Storage Loss:

EF = 0.00016 lb/1000 gal/day (Ref. A-2)

Q = (55,000 Bbl/day)(0.00016 lb/1,000 gal/day)(42 gal/Bbl)

Q = 0.37 lb/day = 0.07 t/yr

Working Loss:

EF = 0.00018 lb/1,000 gal (Ref. A-2)

Q = (7,860 Bbl/day)(42 gal/Bbl)(0.00018 lb/1,000 gal)

Q = 0.06 lb/day = 0.01 t/yr

Total Loss:

	lb/day (t/yr)		
	Storage	Working	Total
Phase I Tank	0.09 (0.02)	0.01 (0.002)	0.10 (0.02)
Phase II Tank	0.37 (0.07)	0.06 (0.01)	0.43 (0.08)
			0.53 (0.10)

II-34. NAPHTHA STORAGE

Emissions are the same as Phase I. See calculation I-31.

II-35. VALVES, FLANGES, PUMP SEALS, ETC.

EF = 50 lb/1000 Bbl (Ref. A-2)

This is the uncontrolled emission factor derived from EPA's emission factor for petroleum refineries.

Good housekeeping and maintenance are expected to provide 50% control.

Q = (57,000 Bbl/day)(50 lb/1,000 Bbl)(0.5)

Q = 1,425 lb/day = 234 t/yr

A.4 PHASE II LEAD EMISSIONS

Lead in Raw Shale Dust:

Pb in raw shale = 3 ppm (Ref. A-9)

Dust emitted = 302 t/yr (see Section B.1)

Q = (302 t/yr)(3 ppm) = 0.00091 t/yr

Lead in Processed Shale Dust:

Pb in processed shale = 3.6 ppm (see Section A.2)

Dust emitted = 152 t/yr (see Section B.1)

Q = (152 t/yr)(3.6 ppm) = 0.00055 t/yr

Lead in Shale Oil Combustion Flue Gases:

EF = 10^{-7} t/Bbl (see Section A.2)

Oil burn rate = 7525 Bbl/day

Q = (7525 Bbl/day)(10^{-7} t/Bbl)(365 day/yr)(0.9)

Q = 0.247 t/yr

Lead from Other Combustion Processes:

Lead emissions from fuel gas and from diesel fuel combustion should be nil.

Total Lead Emissions:

Raw shale dust	0.00091 t/yr
Processed shale dust	0.00055
Shale oil combustion	0.247
	0.25

A.5 PHASE III PARTICULATE, SO_2, NO_x, CO, AND HC EMISSIONS

III-1a. MINING

Particulate:

EF = 0.018 lb/t (Ref. A-1)

Control efficiency = 80% for settling and wet suppression (Ref. A-1)

Q = (176,000 t/day)(0.018 lb/t)(1 - 0.8)

Q = 634 lb/day = 104 t/yr

III-1b. BLASTING

Carbon Monoxide:

EF = 0.22 lb/lb - ANFO (Ref. A-1)

Q = (96,500 lb-ANFO/day)(0.022 lb/lb-ANFO)

Q = 2123 lb/day = 349 t/yr

Nitrogen Oxides:

EF = 0.012 lb/lb-ANFO (Ref. A-1)

Q = (96,500 lb-ANFO/day)(0.012 lb/lb-ANFO)

Q = 1158 lb/day = 190 t/yr

III-1c. DIESEL FUEL COMBUSTION

Particulate:

EF = 22 lb/1000 gal (Ref. A-2)

Q = (30,000 gal/day)(22 lb/1000 gal)

Q = 660 lb/day = 108 t/yr

Carbon Monoxide:

EF = 90 lb/1000 gal

Q = (30,000 lb/day)(90 lb/1000 gal)

Q = 2700 lb/day = 443 t/yr

Hydrocarbons:

EF = 28 lb/1000 gal

Q = (30,000 gal/day)(28 lb/1000 gal)

Q = 840 lb/day = 138 t/yr

Nitrogen Oxides:

EF = 428 lb/1000 gal

Q = (30,000 gal/day)(428 lb/1000 gal)

Q = 12,840 lb/day = 2109 t/yr

Sulfur Dioxide:

EF = 31 lb/1000 gal

Q = (30,000 gal/day)(31 lb/1000 gal)

Q = 930 lb/day = 153 t/yr

III-2a. IN-MINE CRUSHING

Particulate:

EF = 0.02 lb/ton (Ref. A-3)

Control efficiency = 80% (wet suppression and settling)

Q = (88,000 t/day)(0.02 lb/ton)(0.2) = 352 lb/day

Q = 58 t/yr

III-2b. IN-MINE CRUSHING (SECONDARY)

Particulate:

Control efficiency = 99.7% (Baghouse) (Ref. A-2)

Inlet grain loading = 6 gr/scf

Outlet grain loading = (6 gr/scf)(0.003) = 0.018 gr/scf

Q = (30,000 scfm)(0.018 gr/scf) = 540 gr/min

Q = (540 gr/min)(60 min/hr)(lb/7000 gr) = 4.6 lb/hr

Q = 111 lb/day = 18.2 t/yr

III-3. MINE CONVEYOR SURGE BIN

Particulate:

Baghouse (15,000 cfm) to control dust at the surge bin.

Estimated inlet grain loading = 4 gr/scf

Baghouse control efficiency = 99.7%

Outlet grain loading = (4 gr/scf)(0.003) = 0.012 gr/scf

Q = (15,000 cfm)(0.012 gr/scf) = 180 gr/min

Q = 1.5 lb/hr = 37 lb/day = 6.1 t/yr

III-4. MINE CONVEYOR TRANSFER POINTS

Particulate:

$$EF = \frac{0.0018\ (S/5)(U/5)}{(M/2)^2}$$ (Ref. A-5)

S = 3% silt (estimated)

U = 10 mph

M = 1% moisture (estimated)

$$EF = \frac{0.0018\ (3/5)(10/5)}{(1/2)^2}$$

EF = 0.009 lb/t uncontrolled

Wet suppression control efficiency = 90% (Ref. A-5)

No transfer points on Phase I conveyor. One transfer point on Phases II and III conveyors.

Throughput from Phases II and III conveyors is 176,000 - 27,300 = 148,700 t/day

Q = (148,700 t/day)(0.009 lb/t)(1 - 0.9) = 134 lb/day

Q = 22 t/yr

III-5,6. STORAGE SILO FEED

Particulate:

Phase I baghouse = 5,000 cfm

Phase II baghouse = 5,000 cfm

Phase III baghouse = 10,000 cfm

Estimated inlet grain loading = 4 gr/scf

Baghouse control efficiency = 99.7%

Outlet grain loading = (4 gr/scf)(0.003) = 0.012 gr/scf

Q, Phase I baghouse = 12.3 lb/day = 2 t/yr (see previous Phase I calculations)

Q, Phase II baghouse = 12.3 lb/day = 2 t/yr

Q, Phase III baghouse = 24.6 lb/day = 4 t/yr

Total = 12.3 + 12.3 + 24.6 = 49 lb/day = 8 t/yr

III-7,8. SURFACE CRUSHING AND SCREENING

Particulate:

Phase I baghouse = 15,000 cfm

Phase II baghouse = 15,000 cfm

Phase III baghouse = 30,000 cfm

Estimated inlet grain loading = 7 gr/scf

Baghouse control efficiency = 99.7%

Outlet grain loading = 0.021 gr/scf

Q, Phase I baghouse = 65 lb/day (see Phase I calculations)

Q, Phase II baghouse = 65 lb/day

Q, Phase III baghouse = 130 lb/day = 21.3 t/yr

Total = 65 + 65 + 130 = 260 lb/day = 43 t/yr

III-9. FINES RECLAIM CONVEYOR TRANSFER POINTS

Particulate:

$$EF = \frac{0.0018\ (S/5)(U/5)}{(M/2)^2}$$ (Ref. A-5)

S = 15% silt (estimated)

U = 10 mph

M = 1% moisture (estimated)

$$EF = \frac{0.0018\ (15/5)(10/5)}{(1/2)^2} = 0.04 \text{ lb/t uncontrolled}$$

Wet suppression for control = 90%

Throughput = 1800 t/day

Q = (900 t/day)(0.04 lb/t)(0.1) = 3.6 lb/day each

Q = 1.2 t/year each

Q = (total) = (7.2)(2 transfer points) = 7.2 lb/day

Q = (total) = 1.2 t/yr

III-10,11. FINES CONVEYOR FEED

Particulate:

EF = 0.04 lb/t (see Phase I calculations)

Wet suppression for control = 90%

a. Phases I & II conveyor:

Q = (9400 t/day)(0.04 lb/t)(0.1) = 38 lb/day

Q = 6.2 t/yr

b. Phase III conveyor:

Q = (8200 t/day)(0.04 lb/t)(0.1) = 33 lb/day

Q = 5.4 t/yr

c. Summary:

	lb/day	t/yr
Phase I & II conveyor	38	6.2
Phase III conveyor	33	5.4
	71	11.6

III-12,13. FINES CONVEYOR TRANSFER POINTS

Particulate:

EF = 0.04 lb/t (see calculation I-6)

Wet suppression for control = 90%

Phases I & II Sections:

Q = (9400 t/day)(0.04 lb/t)(0.1) = 37.6 lb/day each

Four (4) transfer points.

Q (total) = (38 lb/day)(4) = 152 lb/day = 25 t/yr

Phase III Section:

Q = (8200 t/day)(0.04 lb/t)(0.1) = 32.8 lb/day each

Four (4) transfer points.

Q (total) = (32.8 lb/day)(4) = 131 lb/day = 21.5 t/yr

Summary:

	lb/day	t/yr
Phase I & II Sections	152	25
Phase III Section	131	22
	283	47

III-14. TOSCO RETORT FEED SILOS

Particulate:

Two (2) 5,000 cfm baghouses. One on each retort feed.

Inlet grain loading = 3 gr/scf

Baghouse control efficiency = 99.7%

Outlet grain loading = (3 gr/scf)(0.003) = 0.009 gr/scf

For Phase II Retort:

Q = (5000 cfm)(0.009 gr/scf) = 45 gr/min

Q = (45 gr/min)(60 min/hr)(lb/7000 gr) = 0.4 lb/hr

Q = 9.3 lb/day = 1.5 t/yr

For Phase III Retort:

Q = same as Phase II retort

Q = 9.3 lb/day = 1.5 t/yr

Total:

Q = (2)(9.3 lb/day) = 18.6 lb/day

Q = 3 t/yr

III-15. UNION CONVEYOR FEED

Particulate:

EF = 0.006 lb/t (see calculation I-9)

Wet suppression for control = 90%

Phase I conveyor:

Q = (11,600 t/day)(0.006 lb/t)(0.1) = 7 lb/day

Q = 1.1 t/yr

Phase II conveyor:

Q = (34,800 t/day)(0.006 lb/t)(0.1) = 21 lb/day

Q = 3.4 t/yr

Summary:

	lb/day	t/yr
Phase I conveyor	7	1.1
Phase II conveyor	21	3.4
	28	4.5

III-16. UNION RETORT FEED SILOS

Particulate:

Four (4) 1,000 cfm baghouses.

Q = 2 lb/day each (see calculation I-10)

Q (total) = (2 lb/day)(4) = 8 lb/day = 1.3 t/yr

III-17,18. SUPERIOR CONVEYOR FEED

Particulate:

EF = 0.006 lb/t uncontrolled (see calculation I-11)

Wet suppression for control = 90%

For Phases I and II conveyors:

Throughput = 38,000 t/day

Q = (38,000 t/day)(0.006 lb/t)(0.1) = 23 lb/day = 3.7 t/yr

For Phase III conveyor:

Throughput = 74,000 t/day

Q = (74,000 t/day)(0.006 lb/t)(0.1) = 44 lb/day = 7.3 t/yr

Total = 23 + 44 = 67 lb/day = 11 t/yr

III-19. SUPERIOR CONVEYOR TRANSFER POINT

Particulate:

EF = 0.006 lb/t uncontrolled (see calculation I-11)

Wet suppression for control = 90%

Q = (74,000 t/day)(0.006 lb/t)(0.1) = 44 lb/day = 7.3 t/yr

III-20. SUPERIOR RETORT FEED SILOS AND BINS

Particulate:

Two baghouses on each of the five Superior retorts. One @ 5,000 cfm and one @ 3,200 cfm. Total cfm each retort is 8200 cfm.

Q = 17 lb/day = 2.8 t/yr each (see calculation I-12)

Q = 85 lb/day = 14 t/yr total

III-21. UNION DISCHARGE TO PROCESSED SHALE CONVEYOR

Particulate:

EF = 0.0001 lb/t (see calculation I-13)

Q = (Phase I retort) = (9875 t/day)(0.0001 lb/t) = 1 lb/day

Q = (Phase II retorts) = (1 lb/day each)(3 retorts) = 3 lb/day

Q (total) = 4 lb/day = 0.7 t/yr

III-22. TOSCO DISCHARGE TO PROCESSED SHALE CONVEYOR

Particulate:

EF = 0.0001 lb/t (same as Union)

Q (Phase II retort) = (8235 t/day)(0.0001 lb/t) = 1 lb/day

Q (Phase III retort) = (6731 t/day)(0.0001 lb/t) = 1 lb/day

Q (total) = 2 lb/day = 0.3 t/yr

III-23,24. SUPERIOR DISCHARGE TO PROCESSED SHALE CONVEYOR

Particulate:

EF = 0.0001 lb/t (same as Union)

Q (Phase I retort) = (11,000 t/day)(0.0001 lb/t) = 1 lb/day

Q (Phase II retort) = (21,000 t/day)(0.0001 lb/t) = 2 lb/day

Q (Phase III retorts) = (21,000 t/day each)(0.0001 lb/t) = 2 lb/day ea.

= (2 lb/day)(3) = 6 lb/day

Q (total) = 9 lb/day = 1.5 t/yr

III-25. PROCESSED SHALE CONVEYOR TRANSFER POINTS

Particulate:

$$EF = \frac{0.0018\ (S/5)(U/5)}{(M/2)^2}$$ (Ref. A-5)

S = 20% silt (estimated)

U = 10 mph

M = 15% moisture (estimated)

$$EF = \frac{0.0018(20/5)(10/5)}{(15/2)^2} = 0.0003 \text{ lb/t}$$

Processed shale throughput = 149,000 t/day

Q = (149,000 t/day)(0.0003 lb/t) = 45 lb/day each

Q = 7.3 t/yr each

Three transfer points.

Q (total) = 135 lb/day = 22 t/yr

III-26. PROCESSED SHALE DISPOSAL

Particulate:

a. Load-in by stacker conveyor:

$$EF = \frac{0.0018(S/5)(U/5)(H/10)}{(M/2)^2}$$ (Ref. A-5)

S = 20% silt (estimated)

U = 10 mph

H = 10 ft drop

M = 15% moisture (estimated)

$$EF = \frac{0.0018\ (20/5)(10/5)(10/10)}{(15/2)^2} = 0.0003\ lb/t$$

Q = (149,000 t/day)(0.0003 lb/t) = 45 lb/day

Q = 7.3 t/yr

b. Grooming and compaction:

EF = 16 lb/scraper-hour (uncontrolled) (Ref. A-6)

Q = (112 scraper-hours/day)(16 lb/scraper-hour)
= 1792 lb/day

This will be the worst daily rate. Watering will be used to control dust when practical. On an annual basis, 50% control is expected to be achieved.

Q = 147 t/yr

c. Wind erosion:

EF = 8570 lb/acre-year (see calculation I-18d)

Maximum of 30 acres exposed.

Control efficiency = 85% for compaction and chemical dust suppressants.

$Q = (30 \text{ acres})(8570 \text{ lb/acre-yr})(0.15)(\text{t}/2000 \text{ lb})$

$Q = 19 \text{ t/yr} = 106 \text{ lb/day}$

d. Summary:

	lb/day	t/yr
Load-in	45	7
Grooming and compaction	1792	147
Wind erosion	106	19
	1943	173

III-27. FINES STORAGE

Particulate:

a. Reclaim by front-end loader:

$$EF = \frac{0.0018\ (S/5)(U/5)}{(M/2)^2\ (Y/6)}$$ (Ref. A-5)

S = 15% silt (estimated)

U = 10 mph

M = 1% moisture (estimated)

Y = 10 cu. yds (loader capacity)

$$EF = \frac{0.0018\ (15/5)(10/5)}{(1/2)^2\ (10/6)} = 0.026 \text{ lb/t}$$

$Q = (1800 \text{ t/day})(0.026 \text{ lb/t}) = 47 \text{ lb/day}$

On an annual basis, 50% control is expected to be achieved by watering.

$Q = (47 \text{ lb/day})(0.5)(365 \text{ days/yr})(\text{t}/2000 \text{ lb})(0.9)$

$Q = 3.9 \text{ t/yr}$

b. Wind erosion:

EF = 6427 lb/acre-year (see calculation I-17c)

The storage area will be worked 5 acres at a time.

Q = (5 acres)(6427 lb/ac-yr)(yr/365 days) = 88 lb/day

On an annual basis, 50% control is expected to be achieved by watering.

Q = (88 lb/day)(0.5)(365 days/yr)(t/2000 lb)

Q = 8.0 t/yr

c. Vehicle traffic:

EF = 0.1 K (s/1.5)(d/235) (Ref. A-5)

K = 0.1 (little traffic)

S = 15% silt (estimated)

D = 275 dry days/yr

EF = 0.1(0.1)(15/1.5)(275/235) = 0.12 lb/t

Q = (1800 t/day)(0.12 lb/t) = 216 lb/day

On an annual basis, 50% is expected to be achieved by watering.

Q = (216 lb/day)(0.5)(365 days/yr)(0.9 plant factor) (t/2000 lb) = 17.7 t/yr

d. Summary:

	lb/day	t/yr
Reclaim	47	3.9
Wind erosion	88	8.0
Vehicle traffic	216	17.7

III-28. COARSE SHALE STOCKPILE

Particulate:

a. Load-in

EF = 0.009 lb/t (see calculation I-16a)

Control efficiency = 75% (Lowering well)

Q = (5,000 t/day)(0.009 lb/t)(0.25) = 11 lb/day

Q = 1.8 t/yr

b. Grooming

EF = 0.02 lb/t (see calculation I-16b)

Q = (5,000 t/day)(0.02 lb/t) = 100 lb/day

On an annual basis, 50% control is expected to be achieved by watering.

Q = (100 lb/day)(0.5)(365 days/yr)(t/2000 lb)(0.9)

Q = 8.2 t/yr

c. Wind erosion

EF = 0.32 lb/t-yr (see calculation I-16c)

A total of 3 million tons will be stored in 3 piles. Two of the stockpiles containing 2.5 million tons will be dead storage and will be sealed to prevent wind erosion and to preserve the quality of the raw shale. In the third pile which will contain 0.5 million tons, 65% will be dead storage and will be sealed. Total dead storage = 2.5 + (0.65)(0.5) = 2.83 million tons. Ninety-five percent control of fugitive dust is expected to be achieved.

Dead storage wind erosion:

Q = (2,830,000 t)(0.32 lb/t-yr)(0.05)(yr/365 days)

Q = 124 lb/day = 22.6 t/yr

The remaining 35% of the half-million ton pile will be live storage.

Live storage wind erosion:

Q = (500,000 t)(0.35)(0.32 lb/t-yr)(yr/365 days)

Q = 153 lb/day

On an annual basis, 50% control of fugitive dust from live storage will be achieved by watering.

Q = (153 lb/day)(0.5)(365 days/yr)(t/2000 lb)

Q = 14 t/yr

Total for wind erosion:

	lb/day	t/yr
Dead	124	23
Live	153	14
	277	37

d. Under-the-pile reclaim

Reclaim will be non-routine. Any associated emissions are expected to be approximately offset by the discontinued operation of routine equipment.

e. Summary

	lb/day	t/yr
Load-in	11	2
Grooming	100	8
Wind erosion	277	37
Reclaim	—	—
	388	47

III-29. UNION RECYCLE GAS HEATERS

Heat input = 928 MMBtu oil + 32 MMBtu gas

Heat content oil = 6.09 MMBtu/Bbl

Heat content gas = 887 Btu/scf

Burn rate = (928 MMBtu/hr)/(6.09 MMBtu/Bbl)
+ (32 MMBtu/hr)/(887 Btu/scf)
= 152 Bbl/hr + 36,100 scf/hr

Sulfur Dioxide:

EF = 0.284 lb/10^3 gal + 140 lb/MMscf (see calculation I-19)

Q = (152 Bbl/hr)(42 gal/Bbl)(0.284 lb/10^3 gal)
+ (36,100 scf/hr)(140 lb/MMscf)

Q = 6.9 lb/hr = 165 lb/day = 27.1 t/yr

Particulate:

EF = 3 lb/10^3 gal + 15 lb/MMscf (see calculation I-19)

Q = (152 Bbl/hr)(42 gal/Bbl)(3 lb/10^3 gal)
+(36,100 scf/hr)(15 lb/MMscf)

Q = 19.7 lb/hr = 473 lb/day = 77.6 t/yr

Nitrogen Oxides:

EF = 31 lb/10^3 gal + 210 lb/MMscf (see calculation I-19)

Q = (152 Bbl/hr)(42 gal/Bbl)(31 lb/10^3 gal)
+ (36,100 scf/hr)(210 lb/MMscf)

Q = 205.5 lb/hr = 4,932 lb/day = 810 t/yr

Carbon Monoxide:

EF = 5 lb/10^3 gal + 17 lb/MMscf (see calculation I-19)

Q = (152 Bbl/hr)(42 gal/Bbl)(5 lb/10^3 gal)
+ (36,100 scf/hr)(17 lb/MMscf)

Q = 32.5 lb/hr = 781 lb/day = 128 t/yr

Hydrocarbons:

EF = 1 lb/10^3 gal + 3 lb/MMscf (see calculation I-19)

Q = (152 Bbl/hr)(42 gal/Bbl)(1 lb/10^3 gal)
+ (36,100 scf/hr)(3 lb/MMscf)

Q = 6.5 lb/hr = 156 lb/day = 25.6 t/yr

III-30. TOSCO BALL HEATERS AND LIFT PIPES

Heat input = 417 MMBtu/hr shale oil + 62 MMBtu high-Btu gas (total for two retorts)

Heat content oil = 6.09 MMBtu/Bbl

Heat content gas = 887 Btu/scf

Burn rate = (417 MMBtu/hr)/(6.09 MMBtu/Bbl) + (62 MMBtu/hr)/(887 Btu/scf)

= 68.5 Bbl/hr + 69,900 scf/hr

Sulfur Dioxide:

EF = 0.284 lb/1000 gal + 140 lb/MMscf (see calculation I-19)

Q = (68.5 Bbl/hr)(42 gal/Bbl)(0.284 lb/1000 gal) + (69,900 scf/hr)(140 lb/MMscf)

Q = 10.6 lb/hr = 254.5 lb/day = 42 t/yr

Colony data suggest 95% of the SO_2 may be absorbed by the raw shale. No credit is taken for this, but SO_2 emissions may actually be much lower than estimated.

Nitrogen Oxides:

EF = 31 lb/1000 gal + 210 lb/MMscf (see calculation I-19)

Q = (68.5 Bbl/hr)(42 gal/Bbl)(31 lb/1000 gal) + (69,900 scf/hr)(210 lb/MMscf)

Q = 104 lb/hr = 2492 lb/day = 409 t/yr

Carbon Monoxide:

EF = 5 lb/1000 gal + 17 lb/MMscf (see calculation I-19)

Q = (68.5 Bbl/hr)(42 gal/Bbl)(5 lb/1000 gal) + (69,900 scf/hr)(17 lb/MMscf)

Q = 15.6 lb/hr = 374 lb/day = 61 t/yr

Hydrocarbons:

EF = 0.73 lb/ton - shale feed (Ref. A-7)

Incinerator provides 85% control (Ref. A-7)

Q = (18,500 TPSD) (0.73 lb/t)(1-0.85)

Q = 2026 lb/day = 333 t/yr

Particulate:

Particulate emissions are due primarily to particulate taken up from the raw shale feed by the ball heater flue gas used for preheating. Cyclones at 93.8% control efficiency (Ref. A-2) and venturi scrubbers at 99.5% control efficiency (Ref. A-2) will be employed in series.

Inlet grain loading = 64.5 gr/scf (based on Colony test data, Ref. A-8).

Outlet grain loading = (64.5 gr/scf)(1-0.938)(1-0.995)
= 0.02 gr/scf

Exhaust volume from scrubbers = 262,000 scfm (131,000 each)

Q = (262,000 scfm)(0.02 gr/scf)(lb/7000 gr)(60 min/hr)

Q = 45 lb/hr = 1078 lb/day = 177 t/yr

III-31a. TOSCO ELUTRIATORS

Particulate:

If feasible, a portion of the boiler plant flue gases may be diverted to the TOSCO elutriators to preheat the ceramic heat transfer balls. Only particulate emissions resulting from this operation are estimated below. All boiler plant flue gas emissions are included with the boiler plants.

EF = 1% raw shale feed, uncontrolled (estimated)

Cyclone control efficiency = 93.8% (Ref. A-2)

Venturi scrubber control efficiency = 99.5% (Ref. A-2)

Q = (18,500 TPSD)(1%)(1-0.938)(1-0.995) (2000 lb/t)

Q = 115 lb/day = 19 t/yr

III-31b. TOSCO PROCESSED SHALE MOISTURIZERS

Particulate:

Venturi scrubber @ 99.5% control efficiency.

Inlet grain loading = 4 gr/scf (based on rock cooling operations, Ref. A-4)

Outlet grain loading = (4 gr/scf)(1-0.995) = 0.02 gr/scf

Exhaust volume = (25,000 scfm ea.)(2) = 50,000 scfm

Q = (50,000 scfm)(0.02 gr/scf)(lb/7000 gr)(60 min/hr)

Q = 8.6 lb/hr = 206 lb/day = 34 t/yr

III-32. HYDROGEN PLANTS

3 reformer furnaces (oil and gas fired)

Heat input:

	Oil	Gas
Phase I Plant	420	16 MMBtu/hr
Phase II Plant	785	26
Phase III Plant	785	26
Total	1,990	68

Heat content of oil = 6.09 MMBtu/Bbl

Heat content of gas = 887 Btu/scf

Burn Rates:	Bbl/hr	scf/hr
Phase I Plant	69	18,000
Phase II Plant	129	29,300
Phase III Plant	129	29,300

Sulfur Dioxide:

EF = 0.284 lb/10^3 gal + 140 lb/MMscf (see calculation I-19)

Phase I Plant:

Q = (69 Bbl/hr)(42 gal/Bbl)(0.284 lb/10^3 gal)
+ (18,000 scf/hr)(140 lb/MMscf)

Q = 3.34 lb/hr = 80 lb/day = 13 t/yr

Phase II Plant:

$Q = (129\ Bbl/hr)(42\ gal/Bbl)(0.284\ lb/10^3\ gal)$
$+ (29{,}300\ scf/hr)(140\ lb/MMscf)$

$Q = 5.64\ lb/hr = 135.4\ lb/day = 22.2\ t/yr$

Phase III Plant:

Same size as Phase II Plant

$q = 5.64\ lb/hr = 135.4\ lb/day = 22.2\ t/yr$

Particulate:

$EF = 3\ lb/10^3\ gal + 15\ lb/MMscf$ (see calculation I-19)

Phase I Plant:

$Q = (69\ Bbl/hr)(42\ gal/Bbl)(3\ lb/10^3\ gal)$
$+ (18{,}300\ scf/hr)(15\ lb/MMscf)$

$Q = 8.97\ lb/hr = 215\ lb/day = 35.4\ t/yr$

Phase II Plant:

$Q = (129\ Bbl/hr)(42\ gal/Bbl)(3\ lb/10^3\ gal)$
$+ (29{,}300\ scf/hr)(15\ lb/MMscf)$

$Q = 16.7\ lb/hr = 401\ lb/day = 65.8\ t/yr$

Phase III Plant:

Same size as Phase II Plant

$Q = 16.7\ lb/hr = 401\ lb/day = 65.8\ t/yr$

Nitrogen Oxides:

$EF = 31\ lb/10^3\ gal + 210\ lb/MMscf$ (see calculation I-19)

Phase I Plant:

$Q = (69\ Bbl/hr)(42\ gal/Bbl)(31\ lb/10^3\ gal)$
$+ (18{,}000\ scf/hr)(210\ lb/MMscf)$

$Q = 93.6\ lb/hr = 2247\ lb/day = 369\ t/yr$

Phase II Plant:

$Q = (129\ Bbl/hr)(42\ gal/Bbl)(31\ lb/10^3\ gal)$
$+ (29{,}300\ scf/hr)(210\ lb/MMscf)$

$Q = 174\ lb/hr = 4179\ lb/day = 686\ t/yr$

Phase III Plant:

Same size as Phase II Plant

Q = 174 lb/hr = 4179 lb/day = 686 t/yr

Carbon Monoxide:

EF = 5 lb/10^3 gal + 17 lb/MMscf (see calculation I-19)

Phase I Plant:

Q = (69 Bbl/hr)(42 gal/Bbl)(5 lb/10^3 gal)
+ (18,000 scf/hr)(17 lb/MMscf)

Q = 14.8 lb/hr = 355 lb/day = 58.3 t/yr

Phase II Plant:

Q = (129 Bbl/hr)(42 gal/Bbl)(5 lb/10^3 gal)
+ (29,300 scf/hr)(17 lb/MMscf)

Q = 27.6 lb/hr = 662 lb/day = 109 t/yr

Phase III Plant:

Same as Phase II Plant

Q = 27.6 lb/hr = 662 lb/day = 109 t/yr

Hydrocarbons:

EF = 1 lb/10^3 gal + 3 lb/MMscf (see calcuation I-19)

Phase I Plant:

Q = (69 Bbl/hr)(42 gal/Bbl)(1 lb/10^3 gal)
+ (18,000 scf/hr)(3 lb/MMscf)

Q = 2.95 lb/hr = 70.8 lb/day = 11.6 t/yr

Phase II Plant:

Q = (129 Bbl/hr)(42 gal/Bbl)(1 lb/10^3 gal)
+ (29,300 scf/hr)(3 lb/MMscf)

Q = 5.5 lb/hr = 132 lb/day = 21.7 t/yr

Phase III Plant:

Same as Phase II Plant

Q = 5.5 lb/hr = 132 lb/day = 21.7 t/yr

III-33a. PHASE I BOILER PLANT

See Phase I calculations for emissions from Phase I Boiler Plant (calculation I-21). Emissions are the same in Phase III, except SO_2 emissions are reduced by 80% by FGD.

III-33b. PHASE II BOILER PLANT

Heat input = 485 MMBtu/hr low-Btu gas +
54 MMBtu/hr upgraded shale oil

Heat content of gas = 70 Btu/scf

Heat content of oil = 6.1 MMBtu/Bbl

Gas burn rate = (485 MMBtu/hr)/(70 Btu/scf)
= 6.93 MMscf/hr

Oil burn rate = (54 MMBtu/hr)/(6.09 MMBtu/Bbl)
= 8.9 Bbl/hr

Sulfur Dioxide:

EF = 26.6 lb/MMscf + 0.284 lb/10^3 gal (see calculation I-21)

Q = (6.93 MMscf/hr)(26.6 lb/MMscf) +
(8.9 Bbl/hr)(42 gal/Bbl)(0.284 lb/1000 gal)

Q = 184.4 lb/hr = 4427 lb/day = 727 t/yr

FGD to provide 80% reduction.

Q = (4427 lb/day)(1-0.8) = 885 lb/day

Q = 145 t/yr

Nitrogen Oxides:

EF = 0.2 lb/MMBtu (Design value)

Q = (539 MMBtu/hr)(0.2 lb/MMBtu)

Q = 108 lb/hr = 2587 lb/day = 425 t/yr

Particulate:

EF = 0.03 lb/MMBtu (Design value)

Q = (539 MMBtu/hr)(0.03 lb/MMBtu)

Q = 16 lb/hr = 388 lb/day = 64 t/yr

Carbon Monoxide:

EF = 17 lb/MMscf + 5 lb/10^3 gal (Ref. A-2)

Q = (6.93 MMscf/hr)(17 lb/MMscf) +
(8.9 Bbl/hr)(42 gal/Bbl)(5 lb/10^3 gal)

Q = 120 lb/hr = 2873 lb/day = 472 t/yr

Hydrocarbons:

EF = 1 lb/MMscf + 1 lb/10^3 gal (Ref. A-2)

Q = (6.93 MMscf/hr)(1 lb/MMscf) +
(8.9 Bbl/hr)(42 gal/Bbl)(1 lb/10^3 gal)

Q = 7.3 lb/hr = 175 lb/day = 29 t/yr

III-33c. PHASE III BOILER PLANT

Heat input = 1455 MMBtu/hr low-Btu gas +
161 MMBtu/hr upgraded shale oil

Heat content of gas = 70 Btu/scf

Heat content of oil = 6.1 MMBtu/Bbl

Gas burn rate = (1455 MMBtu/hr)/(70 Btu/scf)
= 20.8 MMScf/hr

Oil burn rate = (161 MMBtu/hr)/(6.1 MMBtu/Bbl)
= 26.4 Bbl/hr

Sulfur Dioxide:

EF = 26.6 lb/MMscf + 0.284 lb/10^3 gal (see calculation I-21)

Q = (20.8 MMscf/hr)(26.6 lb/MMscf) +
(26.4 Bbl/hr)(42 gal/Bbl)(0.284 lb/10^3gal)

Q = 554 lb/hr = 13,286 lb/day = 2128 t/yr

FGD to provide 80% reduction.

Q = (13,286 lb/day)(1-0.8) = 2,657 lb/day

Q = 436 t/yr

Nitrogen Oxides:

EF = 0.2 lb/MMbtu (Design value)

Q = (1616 MMBtu/hr)(0.2 lb/MMBtu)

Q = 323 lb/hr = 7757 lb/day = 1,274 t/yr

Particulate:

EF = 0.03 lb/MMBtu (Design value)

Q = (1616 MMBtu/hr)(0.03 lb/MMBtu)

Q = 48 lb/hr = 1164 lb/day = 191 t/yr

Carbon Monoxide:

EF = 17 lb/MMscf + 5 lb/10^3 gal (Ref. A-2)

Q = (20.8 MMscf/hr)(17 lb/MMscf) +
(26.4 Bbl/hr)(42 gal/Bbl)(5 lb/10^3 gal)

Q = 359 lb/hr = 8619 lb/day = 1416 t/yr

Hydrocarbons:

EF = 1 lb/MMscf + 1 lb/10^3 gal (Ref. A-2)

Q = (20.8 MMscf/hr)(1 lb/MMscf) +
(26.4 Bbl/hr)(42 gal/Bbl)(1 lb/10^3 gal)

Q = 21.9 lb/hr = 526 lb/day = 86 t/yr

III-34. HYDROTREATER

One unit comes on-line each phase

Fuel is high BTU gas (887 Btu/scf)

Heat input to Ph. I unit = 31 MMBtu/hr

Heat input to Ph. II unit = 55.7 MMBtu/hr

Heat input to Ph. III unit = 63.5 MMBtu/hr

Burn rate Ph. I unit = (31 MMBtu/hr)/(887 Btu/scf)
= 35,000 scf/hr

Burn rate Ph. II unit = (55.7 MMBtu/hr)/(887 Btu/scf)

= 62,800 scf/hr

Burn rate Ph. III unit = (63.5 MMBtu/hr)/(887 Btu/scf)

= 71,600 scf/hr

High Btu-gas treated to remove sulfur and ammonia.

Sulfur Dioxide:

EF = 0.49 gr - S/scf (Sulfur content of fuel gas estimated to be the same as Phase I.)

Ph. I Plant:

Q = (35,000 scf/hr) (0.49 gr - S/scf) (lb/7000 gr)
(64 lb - SO_2/32 lb - S) (24 hr/day)

Q = 118 lb/day = 19.3 t/yr

Ph. II Plant:

Q = (62,800 scf/hr) (0.49 gr - S/scf) (lb/7000 gr)
(64 lb - SO_2/32 lb - S) (24 hr/day)

Q = 211 lb/day = 34.7 t/yr

Ph. III Plant:

Q = (71,600 scf/hr) (0.49 gr - S/scf) (lb/7000 gr)
(64 lb - SO_2/32 lb - S) (24 hr/day)

Q = 241 lb/day = 39.5 t/yr

Nitrogen Oxides:

EF = 230 lb/MMscf (Ref. A-2)

Ph. I Plant:

Q = (35,000 scf/hr) (230 lb/MMscf) (24 hr/day)

Q = 193 lb/day = 31.7 t/yr

Ph. II Plant:

Q = (62,800 scf/hr) (230 lb/MMscf) (24 hr/day)

Q = 347 lb/day = 57 t/yr

Ph. III Plant:

Q = (71,600 scf/hr) (230 lb/MMscf) (24 hr/day)

Q = 395 lb/hr = 65 t/yr

Particulate:

EF = 15 lb/MMscf (Ref. A-2)

Ph. I Plant:

Q = (35,000 scf/hr) (15 lb/MMscf) (24 hr/day)

Q = 12.6 lb/day = 2.1 t/yr

Ph. II Plant:

Q = (62,800 scf/hr) (15 lb/MMscf) (24 hr/day)

Q = 22.6 lb/day = 3.7 t/yr

Ph. III Plant:

Q = (71,600 scf/hr) (15 lb/MMscf) (24 hr/day)

Q = 26 lb/day = 4.2 t/yr

Carbon Monoxide:

EF = 17 lb/MMscf (Ref. A-2)

Ph. I Plant:

Q = (35,000 scf/hr) (17 lb/MMscf) (24 hr/day)

Q = 14.3 lb/day = 2.4 t/yr

Ph. II Plant:

Q = (62,800 scf/hr) (17 lb/MMscf) (24 hr/day)

Q = 26 lb/day = 4.2 t/yr

Ph. III Plant:

Q = (71,600 scf/hr) (17 lb/MMscf) (24 hr/day)

Q = 29 lb/day = 4.8 t/yr

Hydrocarbons:

EF = 3 lb/MMscf (Ref. A-2)

Ph. I Plant:

Q = (35,000 scf/hr) (3 lb/MMscf) (24 hr/day)

Q = 2.5 lb/day = 0.4 t/yr

Ph. II Plant:

Q = (62,800 scf/hr) (3 lb/MMscf) (24 hr/day)

Q = 4.5 lb/day = 0.7 t/yr

Ph. III Plant:

Q = (71,600 scf/hr) (3 lb/MMscf) (24 hr/day)

Q = 5.2 lb/day = 0.8 t/yr

III-35. FLARE PILOT

Three flare pilots @ 1 MMBtu/hr high-Btu gas each.
One each phase.

Heat content and sulfur content same as Hydro Treater gas.

Volumetric burn rate = (1 MMBtu/hr)/(887 Btu/scf)
= 1127 scf/hr each

Sulfur Dioxide:

Q = (1127 scf/hr) (0.49 gr - S/scf) (64 lb - SO_2/32 lb - S) (lb/700 gr) = 0.16 lb/hr each

Q = 3.8 lb/day each = 0.6 t/yr each

Q (total) = (0.16 lb/hr) (3) = 0.48 lb/hr total

Q = 11.5 lb/day total =1.8 t/yr total

Nitrogen Oxides:

EF = 230 lb/MMscf

Q = (1127 scf/hr) (230 lb/MMscf) = 0.26 lb/hr each

Q = 6.2 lb/day each = 1.0 t/yr each

Q (total) = (0.26 lb/hr) (3) = 0.78 lb/hr total

Q = 18.7 lb/day total = 3.0 t/yr total

Hydrocarbons:

EF = 3 lb/MMscf

Q = (1127 scf/hr) (3 lb/MMscf) = 0.003 lb/hr each

Q = 0.08 lb/day each = 0.01 t/yr each

Q (total) = (0.003 lb/hr) (3) = 0.01 lb/hr total

Q = 0.22 lb/day total = 0.03 t/yr total

Carbon Monoxide:

EF = 17 lb/MMscf

Q = (1127 scf/hr) (17 lb/MMscf) = 0.02 lb/hr each

Q = 0.46 lb/day each = 0.07 t/yr each

Q (total) = (0.02 lb/hr) (3) = 0.06 lb/hr total

Q = 1.4 lb/day total = 0.23 t/yr total

Particulate:

EF = 15 lb/MMscf

Q = (1127 scf/hr) (15 lb/MMscf) = 0.017 lb/hr each

Q = 0.41 lb/day each = 0.06 t/yr each

Q (total) = (0.017 lb/hr) (3) = 0.05 lb/hr total

Q = 1.2 lb/day total = 0.19 t/yr total

III-36a. PHASE I GAS TREATMENT PLANT

Sulfur recovery = 29.4 t/day

Small quantities of high-Btu gas are used for fuel.

Heat input = 4 MMBtu/hr

Burn rate = (4 MMBtu/hr)/(887 Btu/scf)
= 4510 scf/hr

Sulfur Dioxide:

EF = 4 lb/t (Ref. A-2)

Sulfur production =29.4 t/day

Q = (4 lb/t) (29.4 t/day) = 118 lb/day

Q = 19 t/yr

(Sulfur dioxide from fuel gas is negligible.)

Nitrogen Dioxide:

EF = 230 lb/MMscf (Ref. A-2)

Q = (4510 scf/hr) (230 lb/MMscf) (24 hr/day)

Q = 25 lb/day = 4.1 t/yr

Particulate:

EF = 15 lb/MMscf (Ref. A-2)

Q = (4510 scf/hr) (15 lb/MMscf) (24 hr/day)

Q = 1.6 lb/day = 0.27 t/yr

Carbon Monoxide:

EF = 17 lb/MMscf (Ref. A-2)

Q = (4510 scf/hr) (17 lb/MMscf) (24 hr/day)

Q = 1.8 lb/day = 0.30 t/yr

Hydrocarbons:

EF = 3 lb/MMscf (Ref. A-2)

Q = (4510 scf/hr) (3 lb/MMscf) (24 hr/day)

Q = 0.32 lb/day = 0.05 t/yr

III-36b. PHASE II GAS TREATMENT PLANT

Sulfur recovery = 95.8 t/day

Small quantities of high-Btu gas are used for fuel.

Heat input = 13 MMBtu/hr

Burn rate = (13 MMBtu/hr)/(887 Btu/scf)

= 14,660 scf/hr

Sulfur Dioxide:

EF = 4.6 lb/t (Ref. A-2)

Sulfur production = 95.8 t/day

Q = (4.6 lb/t) (95.8 t/day) = 441 lb/day

Q = 72 t/yr

(Sulfur dioxide from fuel gas is negligible.)

Nitrogen Dioxide:

EF = 230 lb/MMscf (Ref. A-2)

Q = (14,660 scf/hr) (230 lb/MMscf) (24 hr/day)

Q = 81 lb/day = 13 t/yr

Particulate:

EF = 15 lb/MMscf (Ref. A-2)

Q = (14,660 scf/hr)(15 lb/MMscf)(24 hr/day)

Q = 5.3 lb/day = 0.87 t/yr

Carbon Monoxide:

EF = 17 lb/MMscf (Ref. A-2)

Q = (14,660 scf/hr)(17 lb/MMscf)(24 hr/day)

Q = 6.0 lb/day = 1.0 t/yr

Hydrocarbons:

EF = 3 lb/MMscf (Ref. A-2)

Q = (14,660 scf/hr)(3 lb/MMscf)(24 hr/day)

Q = 1.1 lb/day = 0.17 t/yr

III-36c. PHASE III GAS TREATMENT PLANT

Sulfur recovery = 78.8 t/yr

Small quantities of high-Btu gas are used for fuel.

Heat input = 11 MMBtu/hr

Burn rate = (11 MMBtu/hr)/(887 Btu/scf)

= 12,400 scf/hr

Sulfur Dioxide:

EF = 4 lb/t (Ref. A-2)

Sulfur production = 29.4 t/day

Q = (4 lb/t)(78.8 t/day) = 315 lb/day

Q = 52 t/yr

(Sulfur dioxide from fuel gas is negligible.)

Nitrogen Dioxide:

EF = 230 lb/MMscf (Ref. A-2)

Q = 12,400 scf/hr)(230 lb/MMscf)(24 hr/day)

Q = 68 lb/day = 11 t/yr

Particulate:

EF = 15 lb/MMscf (Ref. A-2)

Q = (12,400 scf/hr)(15 lb/MMscf)(24 hr/day)

Q = 4.5 lb/day = 0.73 t/yr

Carbon Monoxide:

EF = 17 lb/MMscf (Ref. A-2)

Q = (12,400 scf/hr)(17 lb/MMscf)(24 hr/day)

Q = 5.1 lb/day = 0.83 t/yr

Hydrocarbons:

EF = 3 lb/MMscf (Ref. A-2)

Q = (12,400 scf/hr)(17 lb/MMscf)(24 hr/day)

Q = 0.89 lb/day = 0.15 t/yr

III-37. CRUDE SHALE OIL STORAGE (Phase III Tanks)

During Phase III, three tanks of 200 feet diameter each will be constructed making a total of seven crude storage tanks. Emissions from Phases I and II tanks are given in calculations I-25, I-26, and II-29.

Oil to be stored @ 100-110°F.

Standing Storage Loss:

$$L = (9.21 \times 10^{-3})(65)\left[\frac{7}{12.2 - 7}\right]^{0.7} 200(150)^{0.5}(4)^{0.7}(0.45)(1)(0.9)(0.84)$$

L = 162 lb/day per tank

L = (162 lb/day)(3 tanks) = 468 lb/day = 88.7 t/yr

Working Loss:

L = (22.4)(7.1)(0.02)/(200 = 0.016 lb/1,000 gal

Q = (50,000 Bbl/day)(42 gal/Bbl)(0.016 lb/1,000 gal)

Q = 33.6 lb/day = 5.5 t/yr

Total Loss:

	lb/day (t/yr)		
	Storage	Working	Total
Ph. I Union Tank	103 (19)	7.7 (1.3)	111 (20)
Ph. I Superior Tank	122 (22)	7.4 (1.2)	129 (23)
Ph. II Combined Tanks	292 (53)	21 (3.5)	313 (57)
Ph. III Combined Tanks	486 (89)	34 (5.5)	520 (95)
			1,073 (195)

III-38. SYNTHETIC CRUDE OIL STORAGE

Three 200-foot diameter tanks will be added in Phase III. Emissions from Phases I and II tanks are given in calculations I-27 and II-30, respectively.

Oil to be stored at 100-110°F. Estimated vapor pressure is 7 psi.

Standing Storage Loss:

$$L = (9.21 \times 10^{-3})(65)\left[\frac{7}{12.2 - 7}\right]^{0.7}(200)(150)^{0.5}(4)^{0.7}(0.045)(1)(0.9)(0.84)$$

L = 162 lb/day per tank

L = (162 lb/day)(3 tanks) = 486 lb/day = 88.7 t/yr

Working Loss:

L = (22.4)(7.1)(0.02)/(200) = 0.016 lb/1,000 gal

Q = (48,300 Bbl/day)(42 gal/Bbl)(0.016 lb/1,000 gal)

Q = 32.5 lb/day = 5.3 t/yr

Total Loss:

	lb/day (t/yr)		
	Storage	Working	Total
Phase I Tank	103 (19)	7.7 (1.3)	111 (20)
Phase II Tanks	292 (53)	20 (3.4)	312 (56)
Phase III Tanks	486 (89)	32 (5.3)	518 (94)
			941(170)

III-39. RECOVERED OIL TANKS

See calculations I-28 and II-31 for emissions from Phase I and Phase II tanks. In Phase III, an additional 10,000 Bbl tank will be constructed. This is the same size as the Phase II tank and emissions are expected to be the same.

	lb/day (t/yr)		
	Storage	Working	Total
Phase I Tank	11 (2.0)	1.3 (0.22)	12 (2.2)
Phase II Tank	19 (3.4)	2.1 (0.34)	21 (3.7)
Phase III Tank	19 (3.4)	2.1 (0.34)	21 (3.7)
			54 (9.6)

III-40. DIESEL FUEL TANKS

See calculations I-29 and II-32 for emissions from Phases I and II diesel tanks. During Phase III, a third diesel tank of 27,000 Bbl capacity will be added.

Storage Loss:

EF = 0.0039 lb/day/1,000 gal (Ref. A-2)

Q = (27,000 Bbl)(42 gal/Bbl)(0.0039 lb/day/1,000 gal)

Q = 4.4 lb/day = 0.81 t/yr

Working Loss:

EF = 0.023 lb/1,000 gal (Ref. A-2)

Q = (450 Bbl/day)(42 gal/Bbl)(0.023 lb/1,000 gal)

Q = 0.43 lb/day = 0.07 t/yr

Total Loss:

	lb/day (t/yr)		
	Storage	Working	Total
Phase I Tank	2.9 (0.53)	0.29 (0.05)	3.2 (0.58)
Phase II Tank	3.7 (0.67)	0.36 (0.06)	4.1 (0.73)
Phase III Tank	4.4 (0.81)	0.43 (0.07)	4.8 (0.88)
			12.1 (2.19)

III-41. FUEL OIL TANKS

See calculations I-30 and II-33 for emissions from Phases I and II tanks. In Phase III, another fixed roof tank of 98,000 Bbl capacity will be added.

Storage Loss:

EF = 0.00016 lb/1,000 gal/day (Ref. A-2)

Q = (98,000 Bbl)(42 gal/Bbl)(0.00016 lb/1,000 gal/day)

Q = 0.66 lb/day = 0.12 t/yr

Working Loss:

EF = 0.00018 lb/1,000 gal (Ref. A-2)

Q = (14,000 Bbl/day)(42 gal/Bbl)(0.00018 lb/1,000 gal)

Q = 0.11 lb/day = 0.017 t/yr

Total Loss:

	lb/day (t/yr)		
	Storage	Working	Total
Phase I Tank	0.09 (0.02)	0.01 (0.002)	0.10 (0.02)
Phase II Tank	0.37 (0.07)	0.06 (0.01)	0.43 (0.08)
Phase III Tank	0.66 (0.12)	0.11 (0.02)	0.77 (0.14)
			1.30 (0.24)

III-42. NAPHTHA STORAGE

Emissions are the same as in Phases I and II. See calculation I-31.

III-43. VALVES, FLANGES, PUMP SEALS, ETC.

EF = 50 lb/1,000 Bbl (Ref. A-2)

This is the uncontrolled emission factor derived from EPA's emission factors for petroleum refineries. Good housekeeping and maintenance are expected to provide 50% control.

Q = (100,000 Bbl/day)(50 lb/1,000 Bbl)(0.5)

Q = 2,500 lb/day = 411 t/yr

A.6 PHASE III LEAD EMISSIONS

Lead in Raw Shale Dust:

Pb in raw shale = 3 ppm (Ref. A-9)

Dust emitted = 612 t/yr (see Section B.1)

Q = (612 t/yr)(3 ppm) = 0.0018 t/yr

Lead in Processed Shale Dust:

Pb in processed shale = 3.6 ppm (See Section A-2)

Dust emitted = 232 t/yr

Q = (232 t/yr)(3.6 ppm) = 0.00084 t/yr

Lead in Shale Oil Combustion Flue Gases:

EF = 10^{-7} t/Bbl (see Section A.2)

Oil burn rate = 14,100 Bbl/day

Q = (14,100 Bbl/day)(10^{-7} t/Bbl)(365 days/yr)(0.9)

Q = 0.463 t/yr

Lead from Other Combustion Processes:

Lead emissions from fuel gas and from diesel fuel combustion are expected to be negligible.

Total Lead Emissions:

Raw shale dust	0.002 t/yr
Processed shale dust	0.0008
Shale oil combustion	0.46
	0.46

REFERENCES — APPENDIX A

A-1 P. W. Marshall, "Mine Dust and Fumes Control," Colony Development Operation, 1974.

A-2 Compilation of Air Pollutant Emission Factors, Second Edition (including Supplements 1-11), U.S. Environmental Protection Agency, Report AP-42, 1980.

A-3 R. A. Wachter, "Fugitive Dust Levels from Stone Crushers," University of Cincinnati, Ohio. Presented at 73rd Annual Meeting of the Air Pollution Control Association, Montreal, Quebec, June 1980.

A-4 Dust Control Bulletin No. 304, American Air Filter Company, Inc., Louisville, KY

A-5 R. Bohn, T. Cuscino, Jr., and C. Cowherd, Jr., Fugitive Emissions from Integrated Iron and Steel Plants, Midwest Research Institute, Kansas City, Missouri, EPA-600/2-78-050, March 1978.

A-6 "Compilation of Past Practices and Interpretations by EPA on the Air Quality Review of Surface Mining Operations," U.S. Environmental Protection Agency, Region VIII, December 1979.

A-7 Based on Colony test data. See "Lift Pipe Hydrocarbon Emissions," Addendum No. 1, Colony PSD application.

A-8 Based on Colony test data. See EPA review of Colony PSD application.

A-9 Trace Elements Associated with Oil Shale and Its Processing, U.S. Environmental Protection Agency, Region VIII, EPA-908/4-78-003, May 1977.

Appendix B

EMISSION CALCULATIONS FOR NON-CRITERIA POLLUTANTS

B.1 PRELIMINARY DATA

Phase I Raw Shale Particulate Emissions:

Mining	18 t/yr
In-mine crushing	13
Mine conveyor surge bin	2
Storage silo feed	2
Surface crushing	11
Fines conveyor feed	2
Fines conveyor transfer points	5
Fines conveyor discharge	2
Union conveyor feed	1
Union retort feed	0.3
Superior conveyor feed	1
Superior retort feed	3
Raw shale stockpile	21
Fines storage	15
	96

Phase I Processed Shale Particulate Emissions:

Union discharge	0.2
Superior discharge	0.2
Spent shale conveyor	1
Processed shale storage	81
	82

Phase II Raw Shale Particulate Emissions:

Mining	55 t/yr
In-mine crushing	40
Mine conveyor surge bin	3
Mine conveyor transfer points	10
Storage silo feed	4
Surface crushing	21
Fines conveyor feed	6
Fines conveyor transfer points	25
TOSCO feed silos	2
Union conveyor feed	4
Union feed silos	1
Superior conveyor feed	4
Superior feed bins	5
Raw shale storage	33
TOSCO lift pipes	89
	302

Phase II Processed Shale Particulate Emissions:

Processed shale conveyor	14
Processed shale storage	111
TOSCO elutriator	10
TOSCO moisturizer	17
	152

Phase III Raw Shale Particulate Emissions:

Mining	104 t/yr
In-mine crushing	76
Mine conveyor surge bin	6
Mine conveyor transfer points	22
Storage silo feed	8
Surface crushing	43
Fines reclaim conveyor	1
Fines conveyor feed	12
Fines conveyor transfer points	47
TOSCO feed bins	3
Union conveyor feed	4
Union retort feed silos	1
Superior conveyor feed	11
Superior conveyor	7
Superior feed bins	14
Fines storage	30
Raw shale storage	47
TOSCO lift pipes	177
	613

Phase III Processed Shale Particulate Emissions:

Processed shale conveyor	25 t/yr
Processed shale storage	173
TOSCO elutriators and moisturizers	34
	232

Shale Oil Burned:

	MMBtu/hr		
	Phase I	Phase II	Phase III
Union recycle gas heaters	211	685	928
H_2 plants	383	1,142	1,990
Boiler plants	28	82	243
TOSCO ball heaters	-	-	417
	622	1,909	3,578

High-Btu Gas Burned:

	MMBtu/hr		
	Phase I	Phase II	Phase III
Union recycle gas heater	29	275	32
H_2 plants	53	96	68
Hydrotreater plants	31	87	150
Flare pilots	1	2	3
Gas treatment plants	4	17	28
TOSCO ball heaters	-	241	62
	118	718	343

Low-Btu Gas Burned:

	MMBtu/hr		
	Phase I	Phase II	Phase III
Boiler plants	255	740	2,195

B.2 BERYLLIUM

Analyses of the WRSP oil shale indicate that Be concentrations in both the raw and the processed shale are below 1 ppm; thus, emissions of beryllium are expected to be near zero.

B.3 FLUORIDES

Phase I:

F in raw shale = 1,200 ppm (as cryolite) (Ref. B-4)

F in raw shale dust = (96 t/yr)(1200 ppm) = 0.115 t/yr

F in processed shale = (1200 ppm)/(0.8 ash) = 1,500 ppm

F in processed shale dust = (82 t/yr)(1500 ppm)

= 0.123 t/yr

F from shale oil combustion:

EF = 54 C (lb/10^{12} Btu) (Ref. B-2)

C = 1 ppm (F in oil) (Ref. B-1)

Q = (622 MMBtu/hr)(54 x 10^{-12})(1)

Q = 0.034 lb/hr = 0.132 t/yr

F from fuel gas cannot be estimated but emissions can be expected to be very low. Gas-oil separation and gas treatment should remove essentially all particulates.

F from diesel oil combustion is nil. (Ref. B-2)

Totals for Phase I:

Raw shale dust	0.115 t/yr
Processed shale dust	0.123
Fuel oil combustion	0.132
Fuel gas combustion	nil
Diesel oil combustion	nil
Total	0.37

Phase II:

F in raw shale dust = (302 t/yr)(1200 ppm) = 0.36 t/yr

F in processed shale dust = (152 t/yr)(1500 ppm) = 0.23 t/yr

F from fuel oil combustion:

EF = 54 lb/10^{12} Btu (Ref. B-2)

Q = (1,909 MMBtu/hr)(54 lb/10^{12} Btu)

Q = 0.103 lb/hr = 0.41 t/yr

F from fuel gas and diesel is expected to be nil.

Totals for Phase II:

Raw shale dust	0.36 t/yr
Processed shale dust	0.23
Fuel oil combustion	0.41
Fuel gas combustion	nil
Diesel fuel	nil
Total	1.0

Phase III:

F in raw shale dust = (613 t/yr)(1200 ppm) = 0.734 t/yr

F in processed shale dust = (232 t/yr)(1500 ppm) = 0.351 t/yr

F from fuel oil combustion:

EF = 54 lb/10^{12} Btu (Ref. B-2)

Q = (3,578 MMBtu/hr)(54 lb/10^{12} Btu)

Q = 0.193 lb/hr

= 0.76 t/yr

F from fuel gas and diesel is expected to be nil.

Totals for Phase III:

Raw shale dust	0.73 t/yr
Processed shale dust	0.35
Fuel oil combustion	0.76
Fuel gas combustion	nil
Diesel fuel	nil
	1.8

Summary:

Phase I	0.37 t/yr
Phase II	1.0
Phase III	1.8
De Minimis	3.0

B.4 SULFURIC ACID MIST

It is assumed 1% of SO_2 emissions oxidize to SO_3, and all SO_3 converts to H_2SO_4.

Phase I:

Mining:

$$Q = (25.5\ t/yr)(1\%)(98/64) = 0.39\ t/yr$$

Union B retorts:

$$Q = (22\ t/yr)(1\%)(98/64) = 0.34\ t/yr$$

Hydrogen plant:

$$Q = (39\ t/yr)(1\%)(98/64) = 0.60\ t/yr$$

Boiler and steam plant:

$$Q = (381\ t/yr)(1\%)(98/64) = 5.8\ t/yr$$

Hydrotreater:

$$Q = (21\ t/yr)(1\%)(98/64) = 0.32\ t/yr$$

Gas treatment plant:

$$Q = (18\ t/yr)(1\%)(98/64) = 0.28\ t/yr$$

Total Phase I H_2SO_4 = 7.7 t/yr

Phase II:

Mining:

$$Q = (81\ t/yr)(1\%)(98/64) = 1.2\ t/yr$$

Union B retorts:

$$Q = (180\ t/yr)(1\%)(98/64) = 2.8\ t/yr$$

TOSCO ball heater and lift pipes:

$$Q = (153\ t/yr)(1\%)(98/64) = 2.3\ t/yr$$

Hydrogen plants:

$$Q = (70\ t/yr)(1\%)(98/64) = 1.1\ t/yr$$

Boiler and steam plants:

$$Q = (221\ t/yr)(1\%)(98/64) = 3.4\ t/yr$$

Hydrotreaters:

$$Q = (55\ t/yr)(1\%)(98/64) = 0.84\ t/yr$$

Gas treatment plants:

$$Q = (90\ t/yr)(1\%)(98/64) = 1.4\ t/yr$$

Total Phase II H_2SO_4 = 13.0 t/yr

Phase III:

Mining:

$$Q = (153\ t/yr)(1\%)(98/64) = 2.3\ t/yr$$

Union B retorts:

$$Q = (27\ t/yr)(1\%)(98/64) = 0.4\ t/yr$$

TOSCO ball heaters and lift pipes:

$$Q = (42\ t/yr)(1\%)(98/64) = 0.6\ t/yr$$

Hydrogen plants:

$$Q = (57\ t/yr)(1\%)(98/64) = 0.9\ t/yr$$

Boiler and steam plants:

$$Q = (659\ t/yr)(1\%)(98/64) = 10.1\ t/yr$$

Hydrotreaters:

$$Q = (94\ t/yr)(1\%)(98/64) = 1.4\ t/yr$$

Gas treatment plants:

$$Q = (146\ t/yr)(1\%)(98/64) = 2.2\ t/yr$$

Total Phase III H_2SO_4 = 17.9 t/yr

Summary:

Phase I	7.7 t/yr
Phase II	13
Phase III	18

B.5 ASBESTOS

No detectable levels have been reported for oil shales. Emissions of asbestos are expected to be negligible.

B.6 VINYL CHLORIDE

Liquid or gas; boiling point = -14°C.

Cl concentration in raw shale = 160 ppm (Ref. B-1)

Potential sources include fuel combustion and other sources of hydrocarbon emissions. Conditions in the combustion environment are extremely unfavorable for the formation of vinyl chloride, and existing emission data for hydrocarbon emissions indicate low emission levels for hydrocarbon groups containing vinyl chloride (Ref. B-2).

Phase I:

Vinyl chloride from shale oil combustion:

$EF = 769\ lb/10^{12}$ Btu as C_3 hydrocarbons (Ref. B-2)

Assuming 1% of C_3 hydrocarbons are vinyl chloride:

$Q = (622\ MMBtu/hr)(769\ lb/10^{12}\ Btu)(0.01)$

$Q = 0.005\ lb/hr = 0.019\ t/yr$

Vinyl chloride from fuel gas combustion:

$EF = 525\ lb/10^{12}$ Btu as C_3 hydrocarbons (Ref. B-2)

Assuming 1% is vinyl chloride:

$EF = 5.3\ lb/10^{12}$ Btu

Heat input from gas = 373 MMBtu/hr

$Q = (373\ MMBtu/hr)(5.2\ lb/10^{12}\ Btu)$

$Q = 0.002\ lb/hr = 0.008\ t/yr$

Vinyl chloride from other potential sources (e.g., oil storage, processed shale cooling) is presumed to be negligible.

Total for Phase I:

Shale oil combustion	0.019 t/yr
Fuel gas combustion	0.008
	0.027

Phase II:

Vinyl chloride from shale oil combustion:

$Q = (1{,}909\ MMBtu/hr)(7.7\ lb/10^{12}\ Btu)$

$Q = 0.015\ lb/hr = 0.059\ t/yr$

Vinyl chloride from fuel gas combustion:

$$Q = (1{,}458 \text{ MMBtu/hr})(5.2 \text{ lb}/10^{12} \text{ Btu})$$

$$Q = 0.008 \text{ lb/hr} = 0.030 \text{ t/yr}$$

Total for Phase II:

Shale oil combustion	0.059 t/yr
Fuel gas combustion	0.030
	0.089

Phase III:

Vinyl chloride from shale oil combustion:

$$Q = (3{,}578 \text{ MMBtu/hr})(7.7 \text{ lb}/10^{12} \text{ Btu})$$

$$Q = 0.028 \text{ lb/hr} = 0.109 \text{ t/yr}$$

Vinyl chloride from fuel gas combustion:

$$Q = (2{,}538 \text{ MMBtu/hr})(5.2 \text{ lb}/10^{12} \text{ Btu})$$

$$Q = 0.013 \text{ lb/hr} = 0.052 \text{ t/yr}$$

Total for Phase III:

Shale oil combustion:	0.109 t/yr
Fuel gas combustion:	0.052
	0.161

Summary:

Phase I	0.027 t/yr
Phase II	0.089
Phase III	0.161

B.7 HYDROGEN SULFIDE

EF = 0.01% of H_2S content of fuel (Ref. B-2)

Emissions from shale oil combustion will be negligible due to the very low sulfur content of the fuel.

Phase I:

Combustion of low-Btu gas in boiler:

Total sulfur content of gas = 175 ppmw

Less than 80% of total sulfur is H_2S.

H_2S content = (175 ppm)(0.8)(34 lb-H_2S/32 lb-S)

= 149 ppm

Gas density = 0.0759 lb/scf

H_2S content = (0.0759 lb/scf)(149 ppm) = 11.3 lb/MMscf

EF = (0.01%)(11.3 lb/MMscf) = 0.0011 lb/MMscf

Q = (3.6 MMscf/hr)(0.0011 lb/MMscf)

Q = 0.0040 lb/hr = 0.016 t/yr

Combustion of high Btu gas:

H_2S content = 0.10 gr/scf

= 14.3 lb/MMscf

EF = (0.01%)(14.3 lb/MMscf) = 0.0014 lb/MMscf

Q = (109,000 scf/hr)(0.0014 lb/MMscf)(24 hrs/day)

Q = 0.0037 lb/day = 0.0006 t/yr

Potential unburned sulfur from tail gas incineration:

Assume any reduced sulfur is H_2S.

Q = (19 t/yr)(32/64)(34/32)(0.01%)

Q = 0.0010 t/yr H_2S

Total for Phase I:

Low-Btu gas	0.016 t/yr
High-Btu gas	0.0006
Gas treatment plant	0.0010
	0.018

Phase II:

Combustion of low-Btu gas:

Q = (10.5 MMscf/hr)(0.0011 lb/MMscf)

Q = 0.012 lb/hr = 0.046 t/yr

Combustion of high-Btu gas:

Q = (0.82 MMscf/hr)(0.0014 lb/MMscf)

Q = 0.0011 lb/hr = 0.0045 t/yr

Potential unburned sulfur from tail gas incineration:

Q = (90 t/yr)(32/64)(34/32)(0.01%)

Q = 0.0048 t/yr

Total for Phase II:

Low-Btu gas	0.046 t/yr
High-Btu gas	0.0045
Gas treatment plants	0.0048
	0.055

Phase III:

Combustion of low-Btu gas:

Q = (31.3 MMscf/hr)(0.0011 lb/MMscf)

Q = 0.034 lb/hr = 0.136 t/yr

Combustion of high-Btu gas:

Q = (0.39 MMscf/hr)(0.0014 lb/MMscf)

Q = 0.0005 lb/hr = 0.0021 t/yr

Potential unburned sulfur from tail gas incineration:

Q = (146 t/yr)(32/64)(34/32)(0.01%)

Q = 0.0078 t/yr

Total for Phase III:

Low-Btu gas	0.136 t/yr
High-Btu gas	0.002
Gas treatment plants	0.008
	0.146

Summary:

Phase I	0.018
Phase II	0.055
Phase III	0.146

B.8 TOTAL REDUCED SULFUR (TRS)

As defined in NSPS for kraft pulp mills, TRS "means the sum of the sulfur compounds hydrogen sulfide, methyl mercaptan, dimethyl sulfide, and dimethyl disulfide".

TRS from shale oil combustion is expected to be negligible due to the very low total sulfur content.

Phase I:

Low-Btu Gas Combustion:

Exact species of non-H_2S sulfur are unknown. If it is assumed all non-H_2S sulfur compounds are methyl mercaptan:

Sulfur in H_2S = (149 ppmw)(32/34) = 140 ppmw

Methyl mercaptan content = (175 - 140)(48/32)

= 52 ppmw CH_3SH

CH_3SH = (0.0759 lb/scf)(52 ppmw) = 3.95 lb/MMscf

As suggested by Ref. B-2, it is assumed 0.01% of reduced sulfur compounds could be emitted.

EF = (0.01%)(3.95 lb/MMscf) = 0.0004 lb/MMscf

$Q = (3.6\ MMscf/hr)(0.0004\ lb/MMscf)$

$Q = 0.0014\ lb/hr = 0.0056\ t/yr$

Adding H_2S from B.7 above:

$Q = 0.0056 + 0.016 = 0.022\ t/yr$

High-Btu gas combustion:

It is estimated that 10% of total sulfur in gas occurs as CH_3SH. The remainder is H_2S, COS, and CS_2.

CH_3SH content = (0.49 gr/scf)(0.10) = 0.05 gr/scf

= 7.1 lb/MMscf

EF = (0.01%)(7.1 lb/MMscf) = 0.00071 lb/MMscf

$Q = (109{,}000\ scf/hr)(0.00071\ lb/MMscf)$

$Q = 7.74 \times 10^{-5}\ lb/hr = 0.0003\ t/yr$

Adding H_2S:

$Q = 0.0003 + 0.0006 = 0.0009\ t/yr$

Total for Phase I:

Low-Btu gas combustion	0.022 t/yr
High-Btu gas combustion	0.0009
Tail gas H_2S	0.0010
	0.024

Phase II:

Low-Btu gas combustion:

$Q = (10.5\ MMscf/hr)(0.0004\ lb/MMscf)$

$Q = 0.004\ lb/hr = 0.016\ t/yr$

Adding H_2S:

$Q = 0.016 + 0.046 = 0.062\ t/yr$

High-Btu gas combustion:

$Q = (0.82\ MMscf/hr)(0.00071\ lb/MMscf)$

$Q = 0.00058\ lb/hr = 0.0023\ t/yr$

Adding H_2S:

$Q = 0.0023 + 0.0045 = 0.0068\ t/yr$

Total for Phase II:

Low-Btu gas combustion	0.062 t/yr
High-Btu gas combustion	0.0068
Tail gas H_2S	0.0048
	0.074

Phase III:

Low-Btu gas combustion:

$Q = (31.3\ MMscf/hr)(0.0004\ lb/MMscf)$

$Q = 0.0125\ lb/hr = 0.05\ t/yr$

Adding H_2S:

$Q = 0.05 + 0.136 = 0.186\ t/yr$

High-Btu gas combustion:

$Q = (0.39\ MMscf/hr)(0.00071\ lb/MMscf)$

$Q = 0.00028\ lb/hr = 0.0011\ t/yr$

Adding H_2S:

$Q = 0.0011 + 0.146 = 0.147\ t/yr$

Total for Phase III:

Low-Btu gas combustion	0.185 t/yr
High-Btu gas combustion	0.147
Tail gas H_2S	0.008
	0.340

Summary:

Phase I	0.024 t/yr
Phase II	0.074
Phase III	0.340

B.9 REDUCED SULFUR COMPOUNDS (RSC)

As defined in the NSPS for petroleum refineries, RSC means hydrogen sulfide, carbonyl sulfide, and carbon disulfide.

RSC from shale oil combustion will be negligible due to the very low sulfur content of the fuel.

Phase I:

Low-Btu Gas Combustion:

Exact species of non-H_2S sulfur compounds are unknown. If it is assumed all non-H_2S sulfur compounds are COS or CS_2, then emission rates would be the same as those calculated for TRS.

Q = 0.022 t/yr from boiler plant.

High-Btu gas combustion:

COS = 0.66 gr/scf

CS_2 = 0.01 gr/scf

H_2S = 0.10 gr/scf

RSC = 0.66 + 0.01 + 0.10 = 0.77 gr/scf

RSC = (0.77 gr/scf)(lb/7,000 gr)(10^6 scf/MMscf)

RSC = 110 lb/MMscf

EF = (110 lb/MMscf)(0.01%) = 0.011 lb/MMscf

Q = (0.11 MMscf/hr)(0.011 lb/MMscf)

Q = 0.0012 lb/hr = 0.0048 t/yr

Total for Phase I:

Low-Btu gas combustion	0.022 t/yr
High-Btu gas combustion	0.005
Tail gas	0.001
	0.028

Phase II:

Low-Btu gas combustion:

Q = 0.062 t/yr (same as TRS)

High-Btu gas combustion:

Q = (0.82 MMscf/hr)(0.011 lb/MMscf)

Q = 0.0090 lb/hr = 0.036 t/yr

Total for Phase II:

Low-Btu gas combustion	0.062 t/yr
High-Btu gas combustion	0.036
Tail gas H_2S	0.005
	0.103

Phase III:

Low-Btu gas combustion:

Q = 0.185 t/yr (same as TRS)

High-Btu gas combustion:

Q = (0.39 MMscf/hr)(0.011 lb/MMscf)

Q = 0.0043 lb/hr = 0.017 t/yr

Total for Phase III:

Low-Btu gas combustion	0.185 t/yr
High-Btu gas combustion	0.017
Tail gas	0.008
	0.210

Summary:

Phase I	0.028 t/yr
Phase II	0.103
Phase III	0.355

B.10 MERCURY

Mercury concentration in raw shale is expected to be less than 0.5 ppm. Because of the low concentration, mercury emissions are expected to be negligible.

REFERENCES — APPENDIX B

B-1 Trace Elements Associated with Oil Shale and Its Processing, U.S. Environmental Protection Agency, Region VIII, EPA-908/4-78-003, May 1977.

B-2 Health Impacts, Emissions, and Emission Factors for Non-criteria Pollutants Subject to De Minimis Guidelines and Emitted from Stationary Conventional Combustion Processes, prepared for U.S. Environmental Protection Agency by TRW Environmental Engineering Division, Redondo Beach, CA, EPA-450/2-80-074, June 1980.

B-3 K. Schwitzgebel, et al., "Trace Element Discharge from Coal-Fired Power Plants", International Conference on Heavy Metals in the Environment, Toronto, Canada, October 1975.

B-4 Personal Communication, C. Evin, Sohio, March 1981.

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